SITING CONSTRAINTS OII WORKSHOP SUMMARIES

INTRODUCTION

On December 20, 2000 the Energy Commission adopted an Order Instituting Informational (OII) Proceeding to gather information on critical issues affecting the Energy Commission's ability to license power plants in light of the state's increasing demand for electricity. (Order No. 00-1220-18) Based on recent cases, such critical issues include the availability of emission offsets, water supply and water quality impacts, transmission line constraints, natural gas supply constraints, local agency and public participation, land use constraints, and problems with the timing of federal permits. In order to gather information on these topics the Siting Committee conducted a series of workshops. For each of these workshops, staff requested a panel of experts, comprised of local, state or federal agencies, industry representatives, interest groups and the public, to attend the workshop and address the issues raised in the Committee's workshop notices. Interested parties were also encouraged to attend the workshop and provide additional oral or written comments on these topics.

The workshops were conducted as follows:

Natural Gas Supply Constraints	1/25/01
Water Supply Constraints	2/08/01
Emission Offset Availability Constraints	2/14/01
Land Use, Local Agency and Public Participation	3/08/01
Transmission Line Constraints	3/15/01
Timing of Local, State and Federal Permits	3/27/01

In order to provide background information and to help focus workshop discussion, staff published a series of staff white papers. These white papers are available upon request, or may be downloaded from the Energy Commission's web site at http://www.energy.ca.gov/siting/constraints/documents/index.html. Also available on the web site are the transcripts of the workshops, visual presentation made during the workshops, and some comments that we received in an electronic format from interested parties.

Enclosed are staff's summaries of the workshop discussions. These contain discussion of the findings of the workshops, and staff's recommendations based on the workshop discussion. Based on the information presented during the workshops, the Siting Committee will prepare a final report that presents its findings and recommendations regarding actions needed to address power plant siting constraints in California. The report will likely be available in May 2001.

If you have questions regarding these workshop summaries or would like to request hard copies of staff white papers or of the workshop presentations, please contact Richard Buell at (916) 653-1614, or by e-mail at rbuell@energy.state.ca.us.

SITING CONSTRAINTS OII (00-SIT-2)
Table of Contents for Workshop Summaries

NATURAL GAS CONSTRAINTS WORKSHOP SUMMARY

INTRODUCTION

On January 25, 2001, the California Energy Commission (Energy Commission) conducted the Natural Gas Constraints Workshop to identify and discuss natural gas supply constraint issues that may affect the licensing of future power plants by the Energy Commission. Issues discussed included: (1) inter- and intra-state gas pipeline capacity; and (2) current natural gas utility curtailment policies/procedures. The purpose of the workshop was to obtain the information needed to develop appropriate actions, if any, to avoid natural gas supply constraints to the licensing of future power plants.

OVERVIEW OF ORAL PRESENTATION

In opening comments, Commissioners Laurie and Pernell explained the purpose of the workshop was to gather as much information as possible on natural gas supply constraints that may affect the Energy Commission's processing of Applications for the Certification of future power plants.

At the beginning of the workshop, Bill Wood, representing Energy Commission staff, summarized the staff's overview paper "Natural Gas Issues That May Affect Siting New Power Plants in California", January 11, 2000. Mr. Wood concluded that while natural gas resources in the U. S. and Canada are adequate to meet California's future needs, the current capacity of reliable gas transmission to meet California's growing gas consumption is questionable. Current inter-state transmission is at a 91% capacity factor, leaving very little space to get gas into seasonal storage facilities that provide for peak gas demand during both winter and summer. Current inter-state transmission capacity is also competing with a growing demand for gas for power plants being built in the states surrounding California, some drawing their gas directly from inter-state transmission pipelines, further constraining downstream capacity.

Traditionally, the inter-state and intra-state transmission pipeline system was developed to meet peak core customer demand, with non-core customers having the capability to switch to alternate fuels. Increasingly, air quality requirements have eliminated the use of alternate fuels, leaving non-core customers, such as power plants, subject to being curtailed and reducing operational levels during peak gas demand periods. This leads to the question of whether curtailment rules should be changed to include the gas requirements of power plants as firm demand. This would significantly increase the future capacity needs of both the inter- and intra-state gas transmission systems. Some relief could be provided by increasing California in-state gas production and by providing ways to use alternate fuels that would meet air quality requirements.

PANEL 1: INTER- AND INTRA-STATE GAS PIPELINE CAPACITY

Kirk Morgan, Kern River Gas Transmission Co., Director, Business Development

The Kern River Gas Transmission Co. supplies California with about 700 million cubic feet per day (MMcf/d), or about ten-percent of the state's total supply. Two expansions, in 2002 and 2003, are planned for meeting new power plant requirements in California and Nevada. These expansions will access increased Rocky Mountain production. A number of competing power plants are proposed by the same sponsors, both upstream of California and in California, leading to the question of whether upstream plants will use pipeline gas and export power to California or whether California will get the gas for new in-state power plants that will contribute to power generation self-sufficiency within California. The current tightness in gas supply capacity would require the expansion of the main pipeline from the Rocky Mountains if a large number of currently proposed power plants were to be built. However, because there are also capacity limitations on the intra-state pipelines, delivery capacity limitations can't be solved with upstream expansion alone. Expanded access to SoCal Gas, in particular at Wheeler Ridge, and at new receipt points, e.g. Adelanto, should be considered. The cost, efficiency, and reliability tradeoffs of electricity vs. gas for transmission pipeline compression was also presented.

Eric Eisenmann, Pacific Gas Transmission Northwest (GTN) and PG&E National Energy Group

The large range in cost for transmission pipeline expansion, $300,000 to $4,200,000 per mile, was explained in terms of variations in size, terrain, and in the type of expansion, e.g. looping, added compression, etc. The description of the process for a transmission pipeline expansion project focused on showing a market for the added gas capacity, both to the Federal Energy Regulatory Commission (FERC) and to financiers. Commissioner Laurie questioned a possible need for mandated capacity expansion versus the current market-driven process to obtain more timely capacity expansions for power plants. Mr. Eisenmann indicated that the FERC might not make such a dramatic change in their approval process, but that it might be possible for California to undertake mandated pipeline projects. The time needed for the approval process varies from about six months to about two years for large projects with the environmental review being the critical path. Commissioner Pernell asked about allowance during construction for future expansion of pipeline capacity. Mr. Eisenmann indicated that it is common to allow for future capacity increase by pre-investment in pipeline steel to allow compression to be added as market demand grows. The current interstate system is not adequate to meet peak power plant demand. Even though there are no current pipeline expansion projects under construction, the Baja Norte project is scheduled for completion in 2002. There is a current open season process for determining the interest for adding more pipeline capacity to PG&E GTN's for delivering Canada's gas to California. Despite the limited delivery capacity of inter-state transmission, price signals are increasing drilling activity and interest in new pipeline concepts to access new gas resources, e.g., in Alaska and the MacKenzie Delta. Mr. Eisenmann concluded by stating that he hopes that the regulatory approval process will be streamlined and that he believes that a pro-rata curtailment is the best curtailment policy.

Dan Thomas, Pacific Gas & Electric Co., Director, Products & Sales, California Gas Transmission (representing PG&E Gas Transmission)

Eighty percent of the storage capacity of Pacific Gas and Electric (PG&E) Gas Transmission, smaller than that of Southern California Gas Company (SoCal Gas), is used primarily for the core market with the remaining 20% for non-core use. Current pipeline and storage capacity are not adequate to meet the non-core power generation demand in low hydro years, although it can still be met in average years. There is a need to increase backbone capacity to provide the needed deliverability to meet the growing power generation demand and to maintain slack capacity. Added storage capacity is also needed—the new Lodi facility is expected to be on-line in late 2001.. The Baja path that receives gas from the southwest will be very expensive to expand. On the other hand, the expansion of the Redwood Path, which receives gas from Canada, would be relatively inexpensive. However, the Redwood Path expansion will create stranded capacity unless there is also an expansion up north off PG&E Gas Transmission—Northwest.

Steve Watson, Southern California Gas, Capacity Planning Manager

SoCal Gas has adequate interruptible backbone capacity and storage capacity to reliably serve its core and non-core customers. Planned increases in pipeline supply backbone will further enhance supply reliability for customers in Southern California. SoCal forecasts of future power generation gas demand assumes that many proposed plants will not be built and that the gas demand for plants that are built will be at least partially offset by retirements of old power plants. SoCal Gas will consider expansions to the extent that shippers are willing to pay for them. The 1992-93 Wheeler Ridge expansion was “at risk” until 2000 when the California Public Utilities Commission (CPUC) allowed it to be rolled into SoCal’s rate structure. SoCal Gas is going to hold open seasons this year to solicit non-core customer interest in expansion of the redelivery system. SoCal Gas can provide the same level of firm service to a new power plant anywhere on the SoCal Gas system as for the existing non-core customers. Completion of new pipeline construction would take about one year after assurance of a long-term commitment necessary for the CPUC and financing are obtained. SoCal can deliver almost 800 MMcf/d to San Diego Gas & Electric (SDG&E), but SDG&E can only redeliver, at most 600 MMcf/d to its customers. To alleviate this constraint, SoCal is constructing a new pipeline to add 70 MMcf/d of low-cost redelivery capacity to SDG&E. This project, along with the Baja Norte project, should eliminate SDG&E’s curtailments of power plants. SoCal has not curtailed core or non-core customers for over ten years.

Craig Chancellor, Calpine, Gas Regulatory Manager

Calpine is securing its own natural gas reserves and production and suggests that California should explore liquefied natural gas (LNG) to increase its gas supply. The market for in-state California natural gas may be limited by gas quality issues that could be resolved by blending California gas with high British Thermal Unit (Btu)-content inter-state pipeline gas. Also, the time needed to enhance pipeline capacity to meet power plant needs should coincide with the timing for the power plant project.

PUBLIC COMMENT

Robert F. Williams, Williams Technical Associates, Inc., President

Mr. Williams questioned whether OPEC price signals affected the price of natural gas, possibly delaying pipeline projects by depressing gas prices, and the price elasticity of natural gas. Mr. Thomas and Mr. Chancellor commented on the first question, noting that the influence of OPEC on gas prices would depend on whether the gas was associated or non-associated. Mr. Wood and Mr. Chancellor commented on the price elasticity of natural gas noting that it would depend on how direct the link of the gas price was to the final paying customer of the product, e.g. electricity.

Steve Moore, San Diego County Air Pollution Control District

Mr. Moore noted to Mr. Watson that SDG&E began in June 2000 delivering up to 70 MMcf/d to a power plant at Rosarita Beach. The new SoCal Gas pipeline will offset this delivery. A new generation unit will begin operation in June 2001, requiring an additional 85 MMcf/d. Even with this new capacity curtailments are a significant possibility in San Diego County.

John Martini, California Independent Petroleum Association (CIPA)

CIPA is commissioning a gas elasticity study that they expect to show that California gas producers, given the proper incentives and regulatory relief, can tap into the 4 trillion cubic feet (Tcf) of on-shore and 21 Tcf of offshore California natural gas reserves and contribute to increasing gas supplies to power plants in California. Mr. Martini indicated that CIPA would be willing to provide a copy of the study when it was completed.

Barry Brunelle, Sacramento Municipal Utility District (SMUD)

Mr. Brunelle asked Mr. Chancellor if Calpine is considering an expansion similar to the Mojave Northwest expansion or some sort of intra-state expansion. Mr. Chancellor replied that they were considering expansions and are continuing to optimize their own proprietary pipeline system.

Azibuike Akaba, Communities for a Better Environment (CBE), Research Associate

Mr. Akaba asked if the quality of natural gas might be compromised, e.g. by allowing a higher sulfur content, in order to increase available gas. Mr. Watson answered that quality compromises were not necessary to increase gas supplies and that blending was used to maintain gas quality.

PANEL 2: CURRENT NATURAL GAS UTILITY CURTAILMENT POLICIES/PROCEDURES

Dan Thomas, Pacific Gas & Electric Co.

The need for gas curtailment typically occurs during extremely cold weather or due to accidental loss of supply, such as a pipeline rupture. Under conditions of inadequate gas supply, CPUC Rule 14 governs the process of remedies implemented by the utility to maintain gas supply to core, especially residential, customers. Operational Flow

Orders with associated penalties, used frequently by PG&E, then diversions, then curtailments are implemented. Mr. Thomas noted that the penalties for non-compliance with curtailment orders by non-core customers might not be large enough to force compliance, especially for power plants selling electricity at high prices.

New storage at Lodi will help avoid curtailments, as would the possible future storage expansion at Wild Goose. Other options might include alternate power plant fuels, currently not likely, and conservation, something PG&E is starting to examine in greater detail. Mr. Thomas concluded by making the following three points: (1) some form of backup fuel may be necessary/economic for power generators; (2) PG&E's system is not currently designed to provide firm service to both core and non-core customers; and (3) added capital investment is required to provide increased gas supply reliability or alternate fuels for power plants.

Mark Seedall, Duke Energy, Director of Electric Modernization

Duke energy owns the Moss Landing, Morro Bay and Oakland power plants in Northern California and operates the South Bay Facility in San Diego. The modernization of all these power plants would increase gas consumption by about 20%, while increasing power output by 40-50%, due to improved efficiency. The costs of such modernization projects requires that an adequate and reliable supply of natural gas is available. This is especially important because air emission regulations prohibit the use of alternate fuels, making modernized power plants completely dependent on natural gas. Commissioner Laurie asked about the costs associated with alternate fuels. He suggested that this issue needed more attention. Mr. Seedall indicated that alternate fuels would not be needed because California had sufficient pipeline and storage capacity. Mr. Wood asked whether the power plant or the gas utility would be responsible for gas storage. This lead to a general discussion of the appropriate assignment of responsibility for gas storage and related delivery capability. Mr. Seedall thought that curtailment rules should be changed to consider the reliability of the electric grid. He also thought that must-run and recently modernized power plants should be given some priority for gas supply.

Mohsen Nazemi, South Coast Air Quality Management District

Mr. Nazemi described South Coast bubble Rule 1135 for utility boilers and bubble Rule 1134 for gas turbines as they were used to reduce air emissions. This lead to emission trading that eventually caused the utilities to find it cheaper to use clean-burning natural gas than alternate fuels. In practice, no fuel oil is currently burned in the South Coast region. Only about one-third of the generation capacity, mostly older units, has air emission controls installed because it was cheaper to purchase credits. However, credits have become very expensive, tilting the cost advantage to controls for reducing air emissions. South Coast has directed is staff to propose changes to remove powerplants from the RECLAIM program, and apply best available retrofit emission control technologies (BARCT) to the powerplants. Once BARCT has been applied, the powerplant may be reintroduced to the RECLAIM program. Alternate fuels do not have much of a chance in this environment. Mr. Nazemi also indicated that electricity curtailment could lead to increased air emissions, citing battery plants as an example. Newer low-sulfur and low-nitrogen fuel oils might be considered, however.

Arden B. Walters, Advanced Energy Research, President (representing ASPEN)

An advantage of alternate backup fuels is that they provide for gas supply interruption due to accidental unplanned pipeline outages, not just for cold weather periods. In this way they provide an additional level of security that pipeline system design cannot. The cost of stored fuel will depend on the design curtailment duration. It could be only for a few cold morning hours, for a week of cold weather or pipeline outage, or for an entire season, as was the case some years ago in California when fuel oil was used extensively at many power plants during the winter months. The current experience with alternate fuels is largely limited to gas turbine peakers because the air emission controls for intermediate and base load combined cycles or boiler units can be fouled by the to use of alternative fuels. Typically the alternate fuel for gas turbine peakers was #2 distillate . Because peaker backup fuels are subject to long storage periods, the tendency of #2 distillate to decompose and clog fuel filters led some utilities to use slightly more expensive, but more stable, jet fuel. The pre-investment to meet the same air emission requirements as for natural gas when using such liquid backup fuels is going to be very high. It is unlikely that dry low-nitrogen oxide (NOx) burners can be made to work for the liquid fuels, requiring a very large over-investment in selective catalytic reduction (SCR) capacity. If alternate fuel backup systems are to be reliable, they must be run on a regular basis, further intensifying the air emission issue. Other options for gas turbine backup fuels include mini LNG storage, expensive, but without a significant air emission handicap, or propane-air, used extensively as a natural gas backup fuel in low-pressure burner applications. Any experience with the use of propane-air, or propane-air-natural gas blends in gas turbines would need to be investigated. In any case, the higher flame speed of the propane would probably cause a very great deterioration in the effectiveness of dry low-NOx burners.

PUBLIC COMMENT

Robert F. Williams, Williams Technical Associates, Inc., President

Mr. Williams suggested that in exchange for an uninterruptible gas supply, power plants supply a 10-20 day natural gas reserve, including a margin and compressor component. Mr. Thomas thought that the generators did have some responsibility for gas supply reliability and that the added cost of reliability should somehow be included in the price of their contracts. Commissioner Pernell inquired as to size of the required storage. Mr. Thomas indicated that the added storage would be provided by the expansion of an existing storage facility, citing a cost of about $75 million to increase injection and/or withdrawal capacity. Mr. Seedall indicated that a 7-day gas supply for a 500 megawatt (MW) combined cycle facility would be about ½ billion cubic feet (Bcf). Mr. Williams next suggested that a policy of power plant technology diversity might be a good idea. Mr. Seedall indicated that he could not imagine anything other than a natural gas power plant because of the environmental rules in California. Finally, Mr. Williams inquired about the exhaustion of emission credits. Mr. Nazemi replied that this was already happening in the South Coast.

Steven Moore, San Diego County Air Pollution Control District

Mr. Moore asked Mr. Nazemi if he had looked at the local impacts of burning alternate fuels, particularly sulfur oxides (SOx) and particulate matter (PM10). Mr. Nazemi replied that he had not because alternate fuels have not been a serious option.

Azibuike Akaba, Communities for a Better Environment, Research Associate

Mr. Akaba asked if there were any existing regulatory priorities for natural gas curtailment, especially residential vs. industry. Mr. Thomas replied that the curtailment order was power plants first, then industrial customers, ensuring gas supply to residential customers. Mr. Akaba next asked Mr. Nazemi if under the reclaim program there was a cap in the use of emission credits making it mandatory to install pollution control equipment. Mr. Nazemi said that there would probably be a minimum requirement for pollution control equipment, but that all the details of the RECLAIM program were not yet worked out.

Nancy E. Ryan, Environmental Defense

Ms. Ryan asked Mr. Nazemi if he knew of examples other than battery plants that would experience increased emissions due to electricity curtailment. Mr. Nazemi said that he thought refineries and other large industrial operations would require emergency plans to shut down for an electricity curtailment. Ms. Ryan asked Mr. Nazemi if a similar problem might occur for gas curtailments, e.g. for power plants. Mr. Nazemi replied that he didn't think so. Questioned if gas curtailment of power plants would result in increased emissions, both Mr. Nazemi and Mr. Seedall indicated that it might be possible in some situations, but that they were not sure.

Written Comments Received After the Workshop

Written comments were received from The Utility Reform Network (TURN), Calpine Corporation, and El Paso Natural Gas Company. The full text of their comments can be found at www.energy.ca.gov/siting/constraints/documents/comments/.

ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 1: The lack of available natural gas pipeline capacity may prevent the licensing of natural gas fired power plants in California.

A. *General Questions*

- *What is the approximate cost of building new pipeline capacity ($/Mile)? How does size and location of the pipeline affect the cost?*
- *What are the steps needed to add new pipeline capacity?*
- *Who is in charge of making the decision to seek new pipeline capacity? Who has the responsibility of providing the final approval?*
- *Describe the federal and state regulatory processes for approving pipeline projects?*
- *How long does it take to construct a new pipeline project, once approved by a regulatory body? What about an expansion project?*

- *Who has the authority to insure that new natural gas infrastructure is available to meet power plant needs at the federal and state levels?*

  Eric Eisenman summarized the process as follows (Kirk Morgan also gave a similar summary of the process):

  1. Open season
  2. Cost estimation
  3. Establish market commitment
  4. FERC application
  5. FERC approval
  6. Acquire materials (turbines & pipe)
  7. Obtain state and federal right of way grants
  8. State and local permitting
  9. Financing
  10. Construction
  11. In service

  The first step in the process of building new inter- or intra-state natural gas capacity is to identify the need for new capacity. There is no state or federal planning process to forecast demand for natural gas and identify the need for new transmission or storage capacity needs. Currently, natural gas suppliers will identify the potential need for capacity additions, and if they believe conditions warrant investigation they will conduct "open seasons" to identify interest in developing new pipeline capacity. Based on the results of the open season, the natural gas suppliers can demonstrate the market need and start to seek financial and regulatory approval. Route selection and environmental review would also add to the time necessary for approval of the expansions. Early identification of both inter- and intra-state pipeline capacity needs to service new powerplant facilities is critical to ensuring that capacity is available when needed. FERC has approval authority for inter-state pipeline capacity projects and the CPUC has approval authority for intra-state projects. Eric Eisenman described the FERC approval process as follows:

  1. Application
  2. Land owner notification
  3. Federal register notice
  4. Interventions and protests
  5. Scoping and public outreach meetings
  6. Preliminary determination (non-environmental issues)
  7. Draft EIS/EA
  8. Final certification

  The time it takes to approve new pipeline capacity varies depending on the type, length of pipeline, location and environmental and regulatory issues that need to be address. New pipeline approval will likely take 1 to 2 years, and increasing capacity by adding additional compressor stations will likely take much less time. The time necessary for construct of new pipeline capacity also vary depending on type, length of pipeline and location. Estimates range of from months to years for the construction times for new pipelines and expansions.

Mr. Eisenmann estimated the cost to range from $300,000 to $4,200,000 per mile depending on the size of the pipeline, terrain, and the nature of the new pipeline capacity (e.g., added compression versus adding new pipelines). Mr. Edward O'Neill estimated the costs for a 30-inch pipeline to range of from $700,000 per mile, in relatively uninhabited desert, to $2,000,000 per mile for more densely populated areas with significant numbers of road crossings.

B. *Questions Related to the Interstate Pipeline System*

- *Is the current interstate natural gas pipeline system serving California adequate to meet existing power plant natural gas demand on a peak month basis?*

  The adequacy of the interstate pipeline system is depended on which natural gas supplier is being examined. The SoCal Gas system is conditional adequate, but the PG&E and SDG&E system require some upgrades. Storage capacity is another issue requiring examination.

- *Are adequate steps being taken to insure that natural gas will be available for future electric generation facilities when the supply is needed?*

  There is no state or federal planning process to forecast demand for natural gas and identify the need for new interstate transmission or storage capacity needs. While some steps are being taken, there was no assurance that adequate steps to ensure the natural gas supply for future power plants in all parts of California are or will be taken.

- *What pipeline projects are currently under consideration to increase capacity to the California border?*

  The projects include:

  - PG&E GT-NW - 200 MMcf/d, in open season
  - Kern River - 126 MMcf/d before FERC
  - Southern Trans – 90 MMcf/d FERC approved
  - El Paso All American Pipeline conversion from oil to natural gas – 500 MMcf/d

- *How much interstate pipeline capacity to California is dedicated to electric generation in the state? Who are the capacity holders? What is done with capacity that is not utilized?*

Kirk T. Morgan provided some information on the powerplants that are served by the Kern River Gas Transmission Company. Dan Thomas provided information that indicated the portion of PG&E GTN's capacity devoted to power production to be 42 percent. Copies of these presentations are on the Energy Commission's web site at www.energy.ca.gov/siting/constraints/documents.

C. *Questions Related to the Instate Pipeline System*

- *What is the current level of pipeline capacity installed in California? Please specify by region or entity to the extent possible.*

  The capacity of the California intra-state gas transmission pipeline system was addressed by a number of the panel members, which can be found at www.energy.ca.gov/siting/constraints/documents. Published sources can be used to obtain reasonable estimates that can be verified by the pipeline owner/operators. No information on gas supply reliability enhancing system interties was provided.

- *What pipeline projects are currently under consideration to increase capacity inside California?*

  Information on currently considered projects was provided, but there was no indication if this information is complete. Project included:

  - PG&E - 200 MMcf/d in Redwood Path likely to occur due to need and low costs
  - PG&E - 200 MMcf/d in Baja Path, questionable to to expense
  - SCG – 70 MMcf/d to SDG&E

- *What are the current storage capacity levels in California? What expansion plans are being considered in California, if any?*

  Information was provided on both current storage capacity and storage expansion plans, but detailed information on capacity and deliverability was not provided.

- *Is the current natural gas utility pipeline system adequate to meet existing and future power plant natural gas demand on a peak demand day? If not, explain the inadequacies and possible steps to mitigate them.*

  This question was answered for SoCal Gas (yes) and PG&E and SDG&E (no). While PG&E explained their inadequacies and suggested some possible steps for mitigation, there was little indication if such steps would be adequate. SDG&E indicated that currently planned pipeline expansion may reduce their inadequacy.

- *Suggest ways that California's natural gas production might be stimulated to play a greater role in meeting future power plant generation needs.*

A number of presenters suggested that increased California in-state gas production would be a great help, there was little offered as to how to accomplish this, except for blending as a strategy. Mr. Chancellor did suggest that gas quality specifications might limit the take of in-state California gas. He suggested that some gas blending might make California gas more marketable. Mr. Martini offered to share CIPA's natural gas elasticity study with the Energy Commission.

Issue 2: Current natural gas utility curtailment policies affect supply of natural gas to power plants during peak demand periods.

- *What are curtailment rules outlined for the investor-owned utilities regulated by the CPUC and entities not regulated by the CPUC?*

  Mr. Thomas, in particular, provided a detailed explanation of curtailment rules under the CPUC. See is a copy of Mr. Thomas presentation at www.energy.ca.gov/siting/constraints/documents. Major federal reallocations and curtailments of natural gas were not covered.

- *In general, describe the curtailment priority process by region to the extent* possible.

The curtailment priority process by region was not covered in detail. Different curtailment rules apply to each gas utility. PG&E's Rule 14 was discussed by Mr. Thomas. He indicated that PG&E has a unique gas diversion process, agreed to by customers and adopted by the CPUC in 1997.

- *What fuel alternatives do generators have when natural gas supply is limited*?

  Air emission regulations in Southern California, and most of the rest of California, do not currently allow for the use of most backup fuels commonly used by power plants elsewhere. Significant added investment in air emission controls may allow such fuels as #2 distillate and/or jet fuel to be used for California gas turbine power plants, but the capital and operating costs would be expected to be very high. Newer low-sulfur and low-nitrogen fuel oils were suggested by Mr. Nazemi as a possible alternate power plant fuels. An analysis the costs of using alternate fuels could be useful in resolving this issue.

- *What changes to the present curtailment policies, if any, are recommended in the current market environment?*

  In general, power generator presenters felt that their gas should not be curtailed, while gas supplier presenters indicated that curtailment of non-core power plant customers might be needed to maintain reliable service to core customers. Mr. Seedall thought that curtailment rules should be changed to consider electric grid reliability and that must-run and recently modernized power plants should be given priority for gas supply. This issue requires further analysis.

- *Is it in the best interest of California's citizens to have power plants subject to curtailment? If so, under what circumstances?*

  Mr. Thomas, in particular, noted that having natural gas and no electricity to power fans/blowers greatly reduces the usefulness of the gas. It can be concluded that power plants subject to gas curtailments that will shut down or reduce the plant operations are not in the best interest of California citizens. If alternate fuels are available to keep the power plant operating, the adverse impact of the gas curtailment is eliminated. This implies a lot of conditions being met by the alternate fuel capability, including meeting environmental regulations and, usually, fuel switching while operating. Stored natural gas would meet these conditions if it could be delivered at adequate throttle pressure to the power plant.

- *To alleviate the possibility of curtailing electric generation, are there any alternatives, such as the use of an alternative fuel, that new electric generation facilities should be required to maintain on-site? What alternative fuel options should be considered?*

  In other parts of the U. S., with less restrictive air regulations, stored fuels are commonly used to compensate for natural gas curtailments at power plants, including gas turbines and combined cycles. Either #2 distillate or jet fuel are the most common fuels stored on-site for gas turbines. On-line fuel switching is possible if this capability is built into the gas turbines. Small-scale LNG storage has been demonstrated, but is expensive. Propane, mixed with air, is a long-proven natural gas backup option that works in most low-pressure burners, but might not perform well in gas turbines, especially regarding air emissions.

- *How may the need for clean air be balanced with the need to insure that there is a stable and reliable supply of electricity to meet California's needs?*

  This issue requires more examination. Both the use alternate backup fuels and the operation of added, or expanded, storage facilities would be expected to add to air emissions.

- *Is there any potential value in curtailing electricity use to reduce natural gas curtailment? If so, what should be the decision process and who should implement it?*

  This issue requires additional analysis.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

1. There is no state or federal planning process to forecast demand for natural gas and identify the need for new inter- and intra-state transmission or storage capacity needs. The Energy Commission should develop and disseminate information on expected future demand for natural gas and potential locations for future powerplant development to improve market efficiency. The Energy Commission should also encourage potential power plant proponents to develop interest in natural gas supplies for their proposed facilities early in the powerplant permitting process.
2. Examine the option of mandated natural gas supply and storage expansions and transmission for meeting California power plant gas requirements in a more timely manner.
3. Analyze the costs and environmental aspects of using alternate backup fuels during gas curtailment at power plants.
4. Identify and analyze ways to increase in-state natural gas production. A major issue is finding more economical ways to blend lower Btu-content California natural gas with inter-state pipeline gas to meet pipeline quality standards.

WATER SUPPLY ISSUES WORKSHOP SUMMARY

INTRODUCTION

On February 8, 2001 the Siting and Environmental Protection Committee of the California Energy Commission (Energy Commission) conducted a workshop on water issues that may constrain the licensing of future power plants in California and to discuss strategies to address these issues. The three topics discussed at the workshop included: (1) water supply and water regulations, (2) technological solutions, and (3) water policy issues.

OVERVIEW OF ORAL PRESENTATIONS

OVERVIEW OF WATER SUPPLY ISSUES

Mr. Joe O'Hagan, representing the Energy Commission staff, provided a brief overview of water issues addressed in siting cases. Although on a statewide basis power plants are not major consumers of water as compared to agricultural and urban uses, powerplant consumption of water on a local level is often large compared to other uses. Therefore, water supply issues are often of concern to the public.

Mr. O'Hagan stated that most proposals for power plant water supply have been workable. However, a lack of information about project impacts on water supply in the early stages of the staff assessment process has often led to delays in completing the siting process.

PANEL 1: WATER SUPPLY AND WATER REGULATIONS

Mr. Ed Anton, Acting Executive Director SWRCB

Mr. Ed Anton stated that the State Water Resources Control Board (SWRCB or State Board) and Regional Water Quality Control Boards (Regional Boards) regulate two aspects of water within California. The first is water supply that is regulated by the State Water Resources Control Board-primarily for power plants through the Policy on Inland Sources of Cooling Water. Water quality is regulated primarily through the Regional Boards through the issuance of discharge permits.

Mr. Anton explained that the State Water Resources Control Board's Policy on Inland Sources of Cooling Water (Order 75-58) sets up a priority of water sources that should be used for cooling, such as wastewater that would otherwise be discharged to the ocean. This policy, however, consistent with the Energy Commission approach to the policy is that it "…was not set up as an absolute…(page 6, lines 22-23)." The policy does call for the consideration of alternative cooling water sources. Also addressed by the policy is the discharge of wastewater. Since the use of evaporative cooling in a power plant concentrates the salts, the policy calls for wastewater to be discharged to salt sinks or lined ponds.

Mr. Anton also explained that there are both federal and state regulations addressing water quality protection. The State Board has adopted a statewide water quality control plan for the discharge of thermal waste to coastal, interstate, and estuarine waters. There are also standards for thermal waste discharge to inland waters contained in water quality control plans adopted by the Regional Boards, subject to the approval of the State Board.

Federal law and regulation also provide rules and water quality standards for various types of discharges for various types of pollutants. These rules and standards are delegated to and administered by the nine Regional Water Quality Control Boards within the state through the National Pollutant Discharge Elimination System (NPDES) permit program. These permits are required for all point source discharges of waste to navigable waters.

The Federal Clean Water Act includes a provision [Section 316(a)] that states that thermal standards can be waived as long as it is shown that a balanced indigenous populations of fish, shellfish, and wildlife can be supported in the water body where the discharge occurs. This provision is incorporated into the state thermal plan as an exception process. However, completing the studies necessary to support that showing takes a fair amount of time. Many power plants are currently operating under such exceptions, but it is not certain how or whether such exceptions can be applied to new or modified discharges needed for powerplant repowerings, refurbishments or modernizations.

Section 316(b) basically calls for the best cooling water intake technology. Since there are no regulations that specify how this is determined, the Regional Boards have dealt with it on a case-by-case basis. The USEPA has proposed regulations for new units or intake structures that are fairly restrictive and would prohibit the use of once-through cooling in all circumstances except where the cooling water was drawn from the open ocean. The regulations are in abeyance pending review by the Bush administration.

Commissioner Laurie asked whether the use of once-through cooling for gas-fired plants is prevalent in older coastal powerplant facilities and coastal repowering or modernization proposals. Mr. Anton stated that once through cooling is prevalent for both existing and repowering or modernized coastal powerplants. However, new inland facilities typically have employed wet cooling tower technologies. The discussion then turned to PG&E's Diablo Canyon and SCE's San Onofre facilities. These facilities both use once-through cooling, but the Diablo Canyon facility's intakes and discharges are located near-shore, while the San Onofre facility's intake and discharge structures are offshore. The impacts of these two facilities are different, and the near-shore intakes and discharges would not be allowed by current regulations.

Commissioner Pernell inquired about water supply sources for inland plants, and Mr. Anton described possible sources for the typical wet-cooling technology, including obtaining new water rights (a long, difficult process, because most are already established) and purchasing water from an entity with existing rights (e.g., an irrigation district).

Commissioner Pernell then inquired about cooling tower blow-down (wastewater) disposal. Mr. Anton and Mr. O'Hagan described various options including discharge to lined evaporation ponds, the local sewer system, into the groundwater through injection wells, and zero discharge facilities where the water is recycled.

Craig Wilson, Chief Counsel, SWRCB

Mr. Craig Wilson described the memorandum of understanding that was entered into between the Energy Commission staff and the Board in 1998 to coordinate the agencies activities with respect to siting issues related to both water supply and water quality. Commissioner Laurie indicated his appreciation for the cooperation with other State agencies. Mr. Wilson then described the two State Broad general policies that where adopted in the early 1970s: the thermal plan that addresses water quality issues, and the cooling policy that addresses supply issues.

Mr. Wilson described how in the Three Mountain AFC proceeding, the cooling policy encouraged the interested parties to negotiate, which resulted in the applicant modifying the project to include a hybrid wet/dry cooling system that reduced consumption of fresh groundwater. Mr. Wilson then addressed the proposed USEPA Section 316(b) regulations discussed previously and the thermal plan. He confirmed that the Bush Administration has held up these regulations by Executive Order. He indicated that on re-powering projects the key issue with respect to the thermal plan and Section 316(a) compliance is the determination of whether the discharges are existing or new – this is being evaluated on a case-by-case basis.

Mr. Anton and Commissioner Laurie further discussed agency cooperation, and then Mr. Anton, Commissioner Laurie, and Mr. O'Hagan discussed groundwater and information availability for adequacy of impact assessment. It was recognized that while most groundwater basins have been reasonably well defined, the behavior of and interaction among local aquifers is sometimes very difficult to assess and predict.

Mr. Kamyar Guivetchi, Statewide Planning Branch, DWR

Mr. Kamyar Guivetchi started by stating that the State Department of Water Resources (DWR) is in the process of updating Bulletin 118 (California's Groundwater), last updated in 1980, with a draft due in the Fall and publication of the final report in 2002. This bulletin will have comprehensive, up-to-date information on the state's groundwater basins. Commissioner Laurie indicated his concern regarding groundwater law and its fluidity. Mr.Douglas Osugi, DWR's Program Manager for the Bulletin 118 update, was introduced. Mr. Osugi described the update process and made the distinction between adjudicated basins (in which the available water is allocated by agreements or the courts and is supervised by a watermaster) and non-adjudicated basins, where it is basically "first come first served", with the local planning agencies responsible for determining adequacy of supplies. The problem in these situations is the lack of information on the safe yield of these basins. So power plant applicants may need to work with local planning agencies to assess yields and impacts and to protect recharge areas and prevent contamination of resources. Mr. Guivetchi added that the surface owner generally has rights to groundwater below, but that groundwater users and the legislature are recognizing the importance of basin planning and management.

Mr. Guivetchi then proceeded with a slide presentation, the data in which are largely based on the DWR's 1998 State Water Plan (the state's water master plan that is updated every five years and for which an EIR is not prepared). He focused on existing supplies and uses – a water budget with existing facilities and projects and forecasts through Year 2020. A pie chart was then presented, showing that a total of 200 million acre-feet of water are potentially available in a year of average precipitation. Surface runoff accounts for 71,000 acre-feet of this. The developed water supply is 57,000 acre-feet (of which some is groundwater).

The 71,000 acre-feet of runoff is distributed differently throughout the state's ten regions, with, in general, much more in the north. And the precipitation and runoff for any given year can vary dramatically from the average. It is important to note that water supplies are moved from region to region within the state; there are regulatory and environmental conditions as well as other constraints that result in water movements less than the capacities of the inter-regional conveyance facilities.

Commissioner Laurie asked about the feasibility of developing those supplies that are still undeveloped. Mr. Guivetchi replied that DWR has looked at additional development and conservation to provide about two million more acre-feet; the smaller streams have not been looked at for additional supplies. There are a lot of interests and concerns about adversely affecting the environment in doing so.

Next, Mr. Guivetchi presented a breakdown of all supplies (78 million acre-feet per year on average) and who is controlling them. The Federal and State surface water projects only account for 30% of the developed surface water resources. A lot of the water is controlled at the local level. About 12.5 million acre-feet come from groundwater and about 300,000 acre-feet come from recycled and desalted water.

Agricultural and environmental uses account for about 45% each and urban uses accounts for 11%. In answer to a question from Commissioner Laurie, Mr. Guivetchi explained that environmental uses (of developed supplies) include water reserved for wild and scenic rivers, in-stream uses, and wildlife refuges. Projecting to 2020, the numbers don't change appreciably, but there's a slight shift predicted from agricultural to urban uses (with environmental uses assumed not to change).

DWR estimates for 1995 base conditions in an average hydrologic water year show a shortage between uses and supplies of about 1.6 million acre-feet, provided by groundwater overdraft. By 2020, because there will be more uses and about the same supply, the shortage or shortfall would be about 2.4 million acre-feet. These shortages are distributed differently around the state.

In the 2020 projections, DWR estimates that there will be a significant increase in recycled and desalted (coastal) water available. Because of the ability of power plants to use these waters, there might be an opportunity to use these waters as the State Board policy suggests rather than using fresh water for powerplant cooling.

Commissioner Laurie noted that the use of recycled water or desalted water suggests new power plant uses in heavily urbanized and coastal areas, where there are other barriers to siting. He believes there will be increasing pressures to locate plants outside of these urban and coastal areas where such resources are not going to be available. So there are going to be conflicts. Mr. Guivetchi noted that agricultural drain water might be more available in the future.

Mr. Guivetchi then showed how additional supplies and conservation can bring the shortfall for 2020 down to about 200,000 acre-feet in an average year, but that in dry years significant shortfalls, particularly in some regions, may still occur. Commissioner Laurie asked about regulatory protection of environmental uses and it was stated that both Federal and State protections are in place, and that in emergencies there is some potential for relaxation of these protections, generally on a case-by-case basis.

Mr. Guivetchi then addressed cost. Groundwater pumping costs range from $10 per acre-foot to about $50 per acre-foot in the north to as high as $130 per acre-foot in the San Francisco Bay region and elsewhere. There is an increasing trend for groundwater basin users to work together to have management plans. AB-3030 has resulted in the establishment of about 150 of those, and about 17 counties have already enacted groundwater management ordinances since 1994. Therefore, in the siting of power plants, it would be very good to work closely with the local entities, especially if they have groundwater management plans and ordinances. In response to Commissioner Pernell, it was noted that many such ordinances deal with export of groundwater and associated impacts. In adjudicated basins (where a court has stepped in and worked with the locals on how the waters would be used and distributed), it would be a more difficult, formal process to gain groundwater supplies.

In his conclusion, Mr. Guivetchi supported State Board Resolution 75-58 in its emphasis on water conservation and use of fresh waters to the least extent possible. DWR needs to work very closely with Commission staff to insure that the next Water Plan update takes into consideration these options and opportunities. Power plant siting should consider and coordinate with CalFed project planning and implementation. Again, coordination with local planning agencies with respect to groundwater supply was stressed. Finally, Mr. Guivetchi summarized the State water planning process, opportunities for input, and the detailed data from 275 analysis units that will be developed and may be useful for siting.

Commissioner Laurie asked about data needs and availability for determining impacts on water supplies; various sources were discussed, including CalFed and local agencies, but project proponent flexibility (e.g., use of combined wet/dry cooling technology) was also recommended. Mr. O'Hagan mentioned that such sources as General Plans and associated EIRs, and water district plans and EIRs can provide some useful information. But in general, these studies are not readily usable in assessing local water (e.g., groundwater drawdown) impacts of power projects. Bill Chamberlain stressed that tradeoffs in energy and water costs can be very important, and that use of water for cooling can be a high-value use, as shown in the High Desert project.

Mr. O'Hagan mentioned that some of the county ordinances encountered on siting cases were not constraints on groundwater pumping, but rather a way of monitoring well drilling and pumping.

Mr. Wayne Hoffman, Regional Environmental Manager, Duke Energy North America

Mr. Wayne Hoffman stated that about 40 percent of the state's generation now employs once-through cooling and most of those plants, about 20,000 megawatts, are located on the coast. About five or six new or modified powerplants, 5000 or 6000 megawatts, are now being proposed. The Moss Landing project is currently under construction, and will use once through cooling. He indicated that the repowering or expansion of capacity at the existing facilities could provide for a substantial amount of generation to meet future demand in California. He stated that once-through cooling is highly efficient, citing a Duke Energy analysis that showed a loss of almost 100 megawatts on a 1,000-megawatt project in going from a once-through cooling system to a dry cooling system. In response to a question from Commissioner Pernell, Mr. Hoffman indicated that the desirability of siting a power plant in a depleted water basin is low, ostensibly because of such a loss in efficiency.

He then indicated that the Coastal Act provides preference and priority for coastal-dependent uses within the coastal zone. He also indicated that State Water Resources Control Board policy gives the second highest priority (after wastewater which is discharged to the ocean) to ocean water for power plant cooling.

Mr. Hoffman then proceeded to describe how these modernized or re-powered plants offer a lot of benefits, largely due to improved efficiencies, most of which Duke Energy presented in the case of its Moss Landing project, including:

- Reduced use of seawater and lower discharge temperature
- Reduced air emissions
- Reduced natural gas consumption
- Reduced noise
- Reduced impingement and entrainment impacts
- Smaller profile (touting the Morro Bay project currently before the Commission)
- Improved coastal access.

Mr. Hoffman regarded the reuse of existing sites and replacing existing plants as a major positive environmental benefit. He believes that avoiding the use of cooling towers on the coast is very important from a visual standpoint because of their size and unsightliness, as well as their noise levels.

With respect to Clean Water Act Sections 316(a) and 316(b), Mr. Hoffman made the following points:

- Many of these existing plants have substantial data regarding their intake and discharge impacts
- Thermal impacts can be easily modeled and future impacts assessed based on past impacts

- The existing discharge and intake systems can be used without major modification, and thereby qualify for treatment under the regulations as an existing facility (e.g., under the balanced indigenous community requirements discussed previously).

Commissioner Laurie asked about the definition of the term “repower”. Mr. Hoffman stated that it is generally used for plant modernization and is not a specifically defined term. He confirmed that he even uses the “repower” term for the Morro Bay project where the entire power plant would be replaced, because the intake and discharge structures would be retained.

Mr. Hoffman went on to explain that new ocean discharges must meet a 20-degree temperature differential (between intake and receiving waters) and a four degree differential between discharge and receiving water at 1000 feet. He believes that the repowered plants can and should be regulated as existing facilities.

Commissioner Laurie then asked if, from a developer's perspective, the federal requirements, as set forth in Sections 316(a) and 316(b), with proper engineering, can be met, and Mr. Hoffman stated that they could.

Commissioner Pernell asked about the permitting role of the Coastal Commission and how the Section 316(a) and (b) requirements are administered, and the roles of the Coastal Commission and the State and Regional Water Boards were discussed, particularly the Federally-delegated authorities of the Water Boards.

Mr. Hoffman then proceeded through some cooling technology comparison slides (impacts, costs, efficiencies) – for a 1,000 megawatt plant, losses of 48, 50, and up to 100 megawatts for natural draft, mechanical draft, and dry cooling technologies were claimed. Commissioner Laurie questioned whether efficiency isn’t just one of various factors that need to be considered (in addition to appearance, water supply, etc.). With respect to operating costs for a 1,000 megawatt plant over 30 years, Mr. Hoffman asserted that wet cooling towers would add $130 million with gas at $3.50/mmBtu and $200 million with gas at $5/mmBtu, and that dry cooling towers would add $500 million at $5/mmBtu and $1.5 billion at today’s prices. He agreed to provide estimates of added costs for consumers at the request of Commissioner Laurie.

Mr. Hoffman closed with a recommendation that when a replacement plant or modernization lowers the water use and reduces biological effects from an existing baseline plan, the project be allowed to move forward without mitigation requirements. For inland projects he recommended greater cooperation with agricultural users and application of zero discharge technologies. Commissioner Laurie pointed out that adjudicated basins have established rules and that attaining water rights elsewhere may be problematic and Mr. Hoffman indicted that a variety of means are available to get water rights, including land purchase and creatively working with the agricultural community.

PANEL 2: TECHNOLOGICAL SOLUTIONS

DR. John Maulbetsch, Consultant to the Energy Commission on the PIER Program

Dr. John Maulbetsch stated that his presentation on cooling technologies would focus on a 500 megawatt gas fired combined cycle plant (170 megawatts from the steam turbine) as opposed to the Duke Energy analysis of 1,000 megawatts steam turbine powerplant.

To condense the steam in Dr. Maulbetsch's model plant, 3,000 acre-feet per year would be needed with wet cooling tower technology, the greatest water consumer in the plant (95%). The technology is called recirculating wet cooling, employing fans, and losing about 2 to 3% of the water to evaporation per cycle through the cooling system. About 10 gallons per minute (gpm) are evaporated; 2 gpm are lost as blowdown. Impacts from this type of cooling technology are related to discharge of the blowdown wastewater, drift deposition, plume visibility, and noise.

Dr. Maulbetsch explained that with dry cooling, steam is ducted to an air-cooled condenser, which is like an auto radiator. There would only be the 5% percent hotel and auxiliary load to consume water, with no blowdown, no drift, and no plume. It can be noisier than a wet cooling tower because a lot more air is circulated. The capital costs of an optimized dry cooling system should be between 1.5 and 2.5 times as much as an optimized wet cooling tower system, based on about ten different studies that have been conducted over the years. Costs were about $17 million for the model plant at a temperature difference of 55 degrees between condensing temperature and ambient temperature. Costs are higher with higher ambient temperatures, and lower with lower ambient temperatures, and they are more variable with dry-cooling systems versus wet-cooling systems. Key capital cost factors include higher materials costs, higher fan costs, and higher costs for more elaborate steam ducting.

In addition, as ambient temperate rises, back pressure goes up and efficiency goes down – it could be as much as a 10% loss (of the 170 steam turbine megawatts in the model 500-megawatt combined cycle plant) – during (seasonal) periods of high temperature.

Dr. Maulbetsch then described three kinds of hybrid wet-dry cooling systems. First was the single tower design in which there is a wet tower on the bottom and a dry tower on the top. Louvers are used to direct the air between the upper and lower sections, as appropriate. Second was the split steam design where there are two parallel cooling systems - a wet cooling tower on one side of the plant, with its condenser, and a dry cooling tower on the other side of the plant. Third was what's often called a swamp cooler, where the inlet air to the dry tower is pre-cooled with something that looks like a conventional wet tower. He also showed an example of high-pressure water spray nozzles, which can make a mist and cool the inlet air, reducing some power losses; the capital cost increase for such a pre-cooling spray arrangement would be much lower than the hybrid tower or the split steam system.

Dr. Maulbetsch concluded that water saving cooling technologies are feasible, but their costs are generally higher than conventional wet cooling technology, due to higher capital costs and some operating penalties of lowered capacity or efficiency. But adding a small amount of water to dry cooling systems can reduce those inefficiencies with only small capital cost increases.

Commissioner Laurie noted that the farther away from the coast you get the hotter it is, but less water is available, so he asked about research into increasing the efficiencies of dry cooling. It was stated that heat exchanger surfaces and manufacturing techniques are being studied and Mr. O'Hagan mentioned that staff is proposing research through EPRI under the PIER program to evaluate the spray enhancement for dry cooling facilities that was described previously.

Mr. Mike DiFilippo, Consultant for the Energy Commission on the PIER Program

Mr. Mike DiFilippo made a presentation describing the use of wastewater in powerplant cooling. Mr. DiFilippo explained that a wet cooling system required some "blowdown" of water to reduce the salt concentrations in the cooling water. Makeup water is needed to replace the water lost through evaporation and to replace the blow-down. Water supplies with lower initial salt concentrations could be cycled through the cooling tower more (high cycles of concentration) and would have smaller amounts of blowdown to dispose of in evaporation ponds or salt concentrating systems.

In coastal plants using a wet cooling system there are typically about five to seven cycles of concentration. In these systems there is no need for higher cycles of concentration, because there is a receiving body of water for blowdown discharge. For inland plants the cycles of concentration must be increased, and blowdown volume minimized because discharge is either not possible or highly restricted.

Mr. DiFilippo stated that there is a variety of degraded water sources in California, including contaminated groundwater, brackish surface waters and brackish ground water, agricultural return water, and reclaimed municipal effluent in large quantities. These waters typically contain common minerals, reclaimed water constituents (such as BOD, ammonia, and phosphate), hazardous contaminants (such as heavy metals, volatile organics, and pesticides), and other chemicals, such as perchlorate, nitrate, sulfide, and fluoride.

To avoid hazards and maintain equipment, these degraded waters need to be treated before use, generally with commercially available technologies, which could include softening, adjusting pH, reducing silica, and removing total dissolved solids. These treatments cost money and use chemicals, and in some cases, power. Sometimes side-stream treatment is needed because of the constituents of the cooling water source. Blowdown may also need to be treated to reduce or eliminate its volume (to zero discharge).

With higher concentrations of some cooling water constituents, different, more costly condenser metallurgies (such as copper-nickel or even titanium rather than brass) may be needed to control corrosion. Also, there are specialty chemicals that may need to be added to the tower to help prevent scale formation, biological formation, and sedimentation from occurring in low flow areas of the system.

Mr. DiFilippo then discussed blowdown post-treatment disposal options. These include large evaporation ponds, brine concentrators with smaller evaporation ponds, and brine concentrators with crystallizers. Evaporation ponds as large as 200 acres have been built, so they need a lot of flat land (63 acres in the desert would be needed for the 500 megawatt combined cycle model plant) and they collect salt over time – they only make sense in hot and dry climates. Brine evaporators can reduce the disposal volume (and evaporation pond acreage requirement) by about 90% and produce high quality distillate water, at a cost of about one megawatt for the 500 megawatt model plant. Adding a crystallizer would eliminate the remaining liquid waste, producing solid salt crystals, at an additional energy cost of about 0.2 megawatts for the 500 megawatt model plant.

In response to questions by Ms. Townsend-Smith, it was explained that no currently operating power plants in California employ crystallizers, but others are in operation elsewhere in the country, and several are proposed for new power plants in California, including the approved High Desert and La Paloma projects.

Mr. DiFilippo then briefly presented some capital costs for the model 500 megawatt plant in the Central Valley and in the desert:

- Evaporation pond only ($32.9 and $22.1 million, respectively)
- Evaporation pond and evaporator ($6.7 and $5.6 million, respectively)
- Evaporation pond, evaporator, and crystallizer ($5.7 million in either location).

Commissioner Laurie then asked about the availability of degraded water for power plants, and Mr. DiFilippo stated that some salty waters are available in the Central Valley, but that he didn't know about availability in the desert.

PANEL 3: WATER POLICY

Mr. Michael Jackson, Water Attorney, Regional Council of Rural Counties

Mr. Michael Jackson stated that the Council's view is that there is ample water for the siting of power plants in the mountains, the foothills, and the Sacramento Valley, but probably not in the Delta itself or in the San Joaquin Valley, due to the characteristics of the state's water distribution system. He recommended not using potable water elsewhere, where alternatives are available. He also registered his concerns about evaporation ponds. He discussed problems at Kesterson Wildlife Refuge in the San Joaquin Valley where birds have been put at risk due to exposure to contaminated water. He also expressed support for use of the crystallizer technology to avoid evaporation ponds.

In reply to an inquiry from Commissioner Laurie, two projects in the Tulare Basin were identified as having evaporation ponds (Elk Hills and Midway-Sunset). Mr. Jackson registered his concerns about salt buildup in the soils there, and, in general, about transfers of water from environmental and agricultural uses where water is in short supply.

Commissioner Laurie expressed his interest in the relationship between rural counties and smaller power plants and concerns about opposition to sites in the mountain or foothill areas. Mr. Jackson replied that possible sites exist – such as abandoned timber and industrial sites that would have abundant water and be near to transmission lines and gas pipelines in some places.

Gerald H. Meral, PhD, Planning and Conservation League (PCL)

Dr. Gerald H. Meral expressed his concern regarding the tightness of water supplies, particularly during drought situations, when there would be less hydro-power available – this is why there is all the more reason to try to the utmost to prevent dedication of fresh water resources to new power plants. He encouraged the Commission to become involved in attempts to find additional subsidies for the use of reclaimed water such as Proposition 13 provided and to urge increased water bond funding in the area of recycled water. He pointed out that it is very hard for the Commission to turn down a power plant because it's using fresh water, if there are no alternatives.

Commissioner Laurie noted that there's no Energy Commission policy dealing with the mandatory use of dry cooling or alternative systems. It is only addressed if upon environmental review it is found that water service is significantly impacted. And more often than not the data reflects the views of the local water districts, that there's an adequate supply of water to serve that project. Dr. Meral then referenced a PCL suit against DWR in which the reliability of delivery (versus a paper commitment) is a key issue.

Dr. Meral noted that there are so many demands for water (environmental demands, industrial, agricultural, etc.) that the Commission should try to develop generation technologies that need little or no water, or require generators to use a reclaimed water source.

Commissioner Laurie ask Dr. Meral about water designated by DWR for environmental uses (i.e., 45 percent of the state supply), and Dr. Meral replied that much of this water is in locations, such as the north coast, that are not the right places for power plant development.

MS. Kaitilin Gaffney, Center for Marine Conservation.

Ms. Kaitilin Gaffney explained that the Center for Marine Conservation is a national environmental organization dedicated to ocean protection. She is speaking up because of concern that we may be shifting siting towards the coast, since we don't have the same water supply issues there. She asked the Commission to look towards alternatives that do not require large volumes of fresh water, estuarine water, or ocean water.

Ms. Gaffney indicted that we need to be looking at dry cooling in all environments, because there is strong evidence that power plants, even those that draw from offshore coastal waters, have very severe impacts on the environment. In response to a question from Commissioner Laurie related to those impacts, she stated that 70 trillion gallons of water go through powerplants every year in this country, mostly coastal waters. These waters contain fish, fish eggs, fish larvae, invertebrate eggs, and invertebrate larvae. She went on to cite fish entrainment and adverse kelp habitat impacts of the San Onofre plant. She stated that reducing or eliminating that volume would have a very immediate and direct benefit on those coastal ecosystems, which are facing increasing pressures from land-based pollution, from over-fishing, and from a variety of different human sources.

Commissioner Laurie then asked about ability to mitigate power plant impacts. Ms. Gaffney said that although we have newer technologies today and the volume of water per unit of energy has dropped because of increases in efficiency, use of 800 million gallons of water a day still causes a great impact – and energy demand is growing. Dr. Meral added that a mitigation lawsuit settlement for San Onofre was in the tens of millions of dollars and much of the mitigation money ended up being spent in San Diego County - they had to go that far south to find places to do the mitigation. He also mentioned that the Huntington Beach power plant intake might have been a factor in the recent near shore contamination episode there, by drawing in offshore sewage outfall discharges.

Ms. Gaffney went on to emphasize the difficulty of projecting impacts of coastal plants, other community concerns, the need for reducing water throughput, and advantages of siting plants closer to growing demand. Commissioner Laurie noted that people are moving inland, making for interesting energy planning. Ms. Gaffney then stressed the need to look at dry cooling, citing its use at 600 plants around the world.

ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 1: What is the Status of California Water Supply?

1. *What are the long-term projections for the availability of fresh inland water (including surface water and groundwater) for industrial uses? What prices are anticipated for these sources of water?*

   Mr. Kamyar Guivetchi, representing that the State Department of Water Resources provided a detailed breakdown of water supply issue in California. The following is from Mr. Guivetchs visual presentation:

California Water Budget
with Existing Facilities and Programs

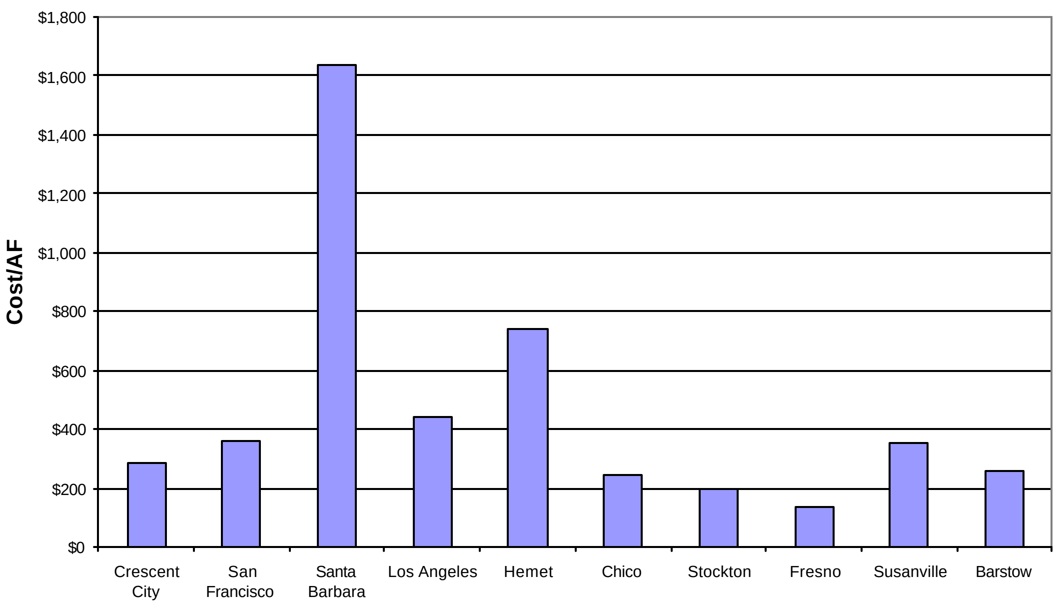
	(million acre-feet) 1995	2020
Water Use		
Urban	8.8	12.0
Agricultural	33.8	31.5
Environmental	36.9	37.0
Total	79.5	80.5
Supplies		
Surface Water	65.1	65.0
Groundwater	12.5	12.7
Recycled and Desalted	0.3	0.4
Total	77.9	78.1
Shortage	1.6	2.4

Source: Bulletin 160-98

Mr. Guivetchi also discussed methods to reduce demand and increase supplies, which would reduce the shortage indented above, which would reduce the shortage in 2020 to 0.2 million acre-feet. An electronic copy of Mr. Guivetchi's visual presentation can be found at www.energy.ca.gov/siting/constraints/documents/2001-02-08_presentations/

Water costs for industrial cities are shown below:

Industrial Water Costs - Selected Cities



Source: Bulletin 160-93

Mr. Guivetchi also provide estimates for groundwater costs, which range from $130 per acre-foot in San Francisco Bay area to $10 per acre-foot in the North Coast area.

2. *How should the Commission apply State Water Resources Control Board Resolution 75-58 in siting cases? Should Resolution 75-58 be clarified or should new policies be developed to guide the continued use or new use of fresh inland waters for industrial purposes?*

   Currently, staff has applied State Water Resources Control Board Resolution 75-58 to mean that an analysis of cooling alternatives should be considered in staff's analysis. However, since the cost of alternatives is generally higher than that of a wet cooling tower using fresh inland water, staff's analyses have only shown that the alternatives are preferred in those instances where their use would eliminate or lessen an environmental impact. Availability of water in California is a critical issue for development in many sectors of the economy, not just the powerplant generation sector. Although there are a number of methods to expanded the supply of water, ultimately there availability/cost will constrain development in California. Many of the panel member expressed concern over the use of water for powerplant cooling, noting that powerplants could be cooled with technologies that would reduce or for all practicable purposes eliminate the use of fresh in-land water. The current application of the SWRCB Resolution 75-58 could be refined to reflect the broader policy issues identified by the panel members.

3. *What alternatives exist for the use of fresh inland water for cooling?*

   a. *What are the environmental consequences of once-through cooling?*

   b. *What is the availability of recycled wastewater?*

   c. *What are the energy and environmental consequences of dry cooling or hybrid wet/dry cooling systems?*

      Dr. John Maulbetsch and Mr. Mike DiFilippo provide a discussion of the cooling alternatives in California. Those include once-through cooling (primarily at coastal sites), wet cooling towers using fresh inland waters, and hybrid wet/dry cooling towers, either wet or wet/dry cooling tower using reclaimed water and dry cooling towers. Once-through cooling can have significant impacts on aquatic biological species due to thermal impacts, impingement and entrainment. Ms. Kaitilin Gaffney, representing the Center for Marine Conservation, provided an overview of possible impacts (see page 28). Mr. DiFilippo discussed possible sources of wastewater, including contaminated groundwater, brackish surface water, brackish groundwater, agriculture return water, reclaimed municipal effluent, and industrial process water or watewater. Mr. DiFilippo did not provide an estimate of the total amount of wastewater available in California. The energy and environmental consequences or dry and hybrid wet/dry cooling systems were discussed by Dr. Maulbetsch. Dr. Maulbetsch explained that with dry cooling, steam is ducted to an air-cooled condenser, which is like an auto radiator. There would only be the 5% percent hotel and auxiliary load to consume water, with no blowdown, no drift, and no plume. It can be noisier than a wet cooling tower because a lot more air is circulated. The capital costs of an optimized dry cooling system should be between 1.5 and 2.5 times as much as an optimized wet cooling tower system, based on about ten different studies that have been conducted over the years. Additional information on cooling systems and wastewater can be found in Mr. Difilippo's and Dr. Maulbetsch's visual presentations, that can be found at: www.energy.ca.gov/siting/constraints/documents/2001-02-08_presentations/

4. *What criteria should the Energy Commission use to evaluate alternatives to the use of fresh inland water for power plant cooling? Are there circumstances in which the Energy Commission should require the use of such alternatives?*

The staff's application of SWRCB Resolution 75-58 results in evaluation of alternative cooling technologies and wastewater sources. As currently applied by staff, this evaluation would only result in requiring an alternative cooling technology, if the staff found that the project would result in significant environmental impacts that could not be mitigated through other means. Staff has generally found the use of available wastewater superior to use of fresh inland water. Some of the panel member suggested a more encompassing evaluation that would consider the social costs and benefits of use of alternative cooling technologies or water sources.

Issue 2: What water supply and water quality constraints exist for siting new powerplants?

1. *How should the Energy Commission evaluate alternative cooling options?*
   a. *What criteria should the Energy Commission use to evaluate alternative cooling options?*
   b. *Are there circumstances in which the Energy Commission should require the use of a specific cooling technology?*

Discussions during the workshop did not provide specific recommendations on how the Energy Commission should evaluate alternative cooling options. One method would be to continue staff's application of SWRCB Resolution 75-58. However, there was some discussion that staff' evaluation is not broad enough to consider the social implications of use of fresh inland water for powerplant cooling. Another method would be to expand staff's application to consider the social implications. Still another method could be to require the use of a hybrid wet/dry or dry cooling system, unless an applicant could demonstrate that need to ensure the electric system reliability and serve load by siting a powerplant at a specific location, are not economic feasible using a hybrid wet/dry or dry cooling system.

2. *What information is required for coastal projects using once-through cooling?*

   a. *Should coastal repowering projects be treated as new projects or existing projects?*

   b. *How can the data gathering be expedited?*

   c. *What criteria should the Energy Commission use to evaluate alternative cooling technologies? Are there circumstances in which the Energy Commission should prohibit the use of once-through cooling?*

   d. *What is the best way to coordinate the requirements of the State Water Resources Control Board's Thermal Plan and Ocean Plan with the Energy Commission's siting process?*

   Again, these questions were not address in great detail by the workshop panel members. There was disagreement on whether coastal repowering project should be treated as new or existing projects, which would determine what requirements these systems would need to met. This issue may be addressed by pending federal rulemaking. Methods to expedite data gathering were also addressed at the workshop on Timing of Federal Permits. It is clear that the Energy Commission should provide clear early guidance to project developers on what information is necessary to approve once-through cooling systems. Staff should also evaluate alternative cooling technologies, including wastewater cooling systems, hybrid wet/dry and dry cooling systems as part of its evaluation of feasible methods to lessen or eliminate impacts on aquatic biological resources. Staff should continue working with local, state and federal agencies to ensure that their policies are addressed in the siting process.

3. *How should the Energy Commission evaluate local water issues?*

   a. *How should the Energy Commission evaluate well interference, the cumulative impacts caused by the project's contribution to reductions in flow and/or lowering of the water table, and impacts caused by pumping in a contaminated aquifer?*

   b. *What criteria should the Energy Commission use to evaluate the feasibility of alternative water supplies and alternative cooling methods? Are there circumstances in which local water issues should result in the Energy Commission requiring the use of an alternative water supply or an alternative cooling method?*

These questions whether not addressed in great detail during the workshops. Many of the panel members supported staff's approach to evaluating local water issues, and its evaluation of alternative cooling technologies and water sources. Still other panel members advocated a more rigorous consideration of the water policy issue raised by the use of fresh inland water for powerplant cooling.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

The supply of water in California is critical for development in every sector of the economy. Although there are a number of sources from which water supply can be expanded, ultimately there is a limited supply of water in California. It is in the states interest to estimate the need for water in the state from all sectors and to evaluate options for expanding the supply of water, and to evaluate alternatives to the use of fresh inland water, including ground water. Staff recommends that the Energy Commission consider the following to ensure that an adequate supply of water is available for powerplant cooling in the state.

A. The Energy Commission staff should provide DWR with estimates of the existing and future needs for water for powerplant cooling, to facilitate DWR's water resource planning efforts.

B. The Energy Commission staff should work with DWR and the State Water Resources Control Board (SWRCB) to identify potential sources of water for powerplant cooling. These sources should include wastewater and fresh water (including ground water). Staff, DWR and SWRCB should also identify areas in the state where powerplant development using fresh water should be discouraged, due to critical under supply of fresh water or due to expected future growth in other sectors of the economy.

C. The Energy Commission staff should work with the Coastal Commission, Regional Water Quality Control Boards and State Water Resources Control Board to identify potential future locations for coastal repowering powerplant development, to identify issues that must be addressed before approving that development, and to identify the information that powerplant developers will need to obtain to expedite licensing of these repowering powerplants.

D. Staff recommends that the Energy Commission develop and implement a policy that requires new generation to maximize water conservation measures for power plant cooling. SWRCB Resolution 75-58 requires the evaluation of alternative water supplies and/or cooling technologies. This policy, however, merely mandates the consideration of alternatives and does not prohibit the use of freshwater for cooling, even if such alternatives are readily available. Therefore, staff believes that this policy does not adequately address the true costs of using fresh or even potable water for power plant cooling in California. In light of California's looming water supply crisis, the use of fresh or even potable water for power plant cooling poses issues that are ignored by the economic or California Environmental Quality Act (CEQA) criteria used by staff in past siting cases to determine the suitability of using alternative sources of cooling water or alternative cooling technology. For example, due to the greater capital cost and efficiency penalty associated with dry cooling, the reliance on economic criteria will almost always favor wet cooling and ignores long term reliability concerns as well as issues of protection of a limited resources.

The greatest emphasis in such a policy should be given to the use of dry cooling because, although more expensive, dry cooling significantly reduces facilities' water demand, removes a major siting constraint and ensures facility reliability during emergencies and droughts.

Emphasis should also be on using alternative sources of cooling water-such as wastewater, brackish groundwater, etc. These sources provide many of the same benefits of using dry cooling, although information requirements to properly evaluate such alternatives may delay the siting process. Finally, the policy should require whenever the use of fresh water is unavoidable, the maximum utilization of this resource. Projects using freshwater should be required to cycle this water 20 times or more and utilize zero discharge. This way the maximum use of the resource is achieved without raising water quality issues from wastewater discharge.

EMISSION OFFSETS AVAILABILITY ISSUES WORKSHOP SUMMARY

INTRODUCTION

On February 14, 2001, the California Energy Commission (Energy Commission) conducted the Emission Offsets Availability Issues Constraints Workshop to identify and discuss emission offset constraint issues that may affect the licensing of future power plants by the Energy Commission. The workshop focused on the following topics: (1) emission offset regulations and availability; and (2) measures to increase offset availability. The purpose of the workshop was to obtain the information needed to develop appropriate actions, if any, to avoid emission offset constraints to the licensing of future power plants.

OVERVIEW OF ORAL PRESENTATIONS

After Commissioners Laurie and Pernell explained the purpose of the workshop, William Walters, of Aspen Environmental Group, an Energy Commission subcontractor, summarized the staff's overview paper, available before the workshop in a February 1, 2001, entitled "Emission Offsets Availability Issues". This included the air quality regulatory requirements for emission offsets and the variability in these regulations between air districts; and the general method for creating emission reduction credits was then discussed. Some air districts allow inter-pollutant trading and some allow inter-basin trading; all have specific requirements that trading provide a net air quality benefit. Offsets are required in most areas of California for projects within the Energy Commission's jurisdiction. Emission Reduction Credit (ERC) availability is becoming a constraint in the siting process in some areas and the cost of ERCs is increasing rapidly. A few case histories were summarized, including the inter-pollutant trading that has been performed in the Bay Area and San Joaquin Valley.

PANEL 1: EMISSION OFFSET REGULATORY REQUIREMENTS

Duong Nguyen, United States Environmental Protection Agency

EPA requires that offsets be from emission reductions that are permanent, quantifiable, enforceable and surplus. Further emission reductions must be achieved prior to beginning construction of any new source that triggers offset requirements. EPA allows inter-district/inter-basin emission reduction credit trading when trading from an upwind district/basin of worse air quality to a down wind district/basin. EPA allows inter-pollutant trading for pollutants with known precursor effects, but they do not encourage its use due to the uncertainties regarding what offset ratios will properly offset impacts. EPA also allows the use of mobile source emission reduction credits (MERCs). The requirement for offsets and offset ratios are tied to the required dates for attainment and magnitude of non-attainment. Additionally, there are mandated emission reductions for non-attainment areas specified in the State Implementation Plan (SIP) and requirements to reach attainment goals by specified dates. If the mandated emission reductions or attainment goals are not met then offset trigger levels can be lowered, required offset ratios can be raised to as high as 2:1 and other sanctions, such as reductions in highway funding, can occur.

Mohsen Nazemi, South Coast Air Quality Management District

The South Coast Air Quality Management District (SCAQMD) has permitting authority for the South Coast Air Basin (SCAB), with over 29,000 permitted facilities and 15 million people. For the power plant licensing process, SCAQMD issues a Preliminary Determination of Compliance (PDOC), a Final Determination of Compliance (FDOC), and operating permits (including the Title V operating permit). EPA has final authority over the Title V operating permit. The offset requirements for SCAQMD are based on Federal, State and local regulations. SCAQMD's attainment status (severe non-attainment for ozone, non-attainment for PM10 and non-attainment for CO concentrations) drives its regulatory requirements. The New Source Review process first requires sources to install Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) technology, as well as, offset emissions when they are greater than 4 tons per year for any of the criteria pollutants, using emission reduction credits at a ratio of 1.2 to 1. Sources below 4 tons per year also require emission offsets; however, these offsets are provided by SCAQMD. Additionally, SCAQMD has an emission reduction credit priority reserve for use at facilities that provide an essential public service. Power plants are currently in the RECLAIM program for NOx emissions. There are approximately 380 sources in the RECLAIM program and 28,000+ facilities in the regular permitting/offset program.

Emission reduction credits are created by facility shutdown and control beyond BACT requirements. Normally, ERCs can be created when reductions beyond Reasonably Available Control Technology (RACT) are made; however, SCAQMD can only approve ERCs for those reductions beyond BACT emission levels. SCAQMD allows certain inter-pollutant ERC use but only allows district ERCs to be used as inter-district/basin offsets for downwind districts. The SCAQMD ERC bank is currently low in PM10 credits due to recent transactions (mainly relating to new power projects). Costs for ERCs have increased substantially, with 2 to 5 fold increases in prices over the last few years. The RECLAIM program is currently applicable for power plant NOx emissions; however, the District is undergoing rulemaking revisions to allow power plants to opt out of the RECLAIM program for NOx or opt into the RECLAIM program for SOx. They are also investigating the creation of air quality investment programs for sources to fund district creation of ERCs. The 1999 NOx emissions for RECLAIM sources were above their allocations and the price for NOx RECLAIM Trading Credits (RTCs) has increased by over ten-fold. SCAQMD is trying to stabilize the cost for NOx RTCs. Additionally, the District is interpreting and will implement the requirements of AB 970 and the recent executive orders to the best of their ability in order to help site new power projects within the SCAB.

Steve Moore, San Diego Air Quality Management District

No state offsets are currently required under AB 3319 for the San Diego Air Basin as long as the district demonstrates no net increase in pollutants. However, due to growth in the area, that may not be possible in the future. No CO, SOx, or PM10 offsets are required under federal regulations for the San Diego District. NOx and VOC emissions must be offset at a 1.2:1 ratio for projects with emissions above 50 tons per year. For comparison, the proposed Otay Mesa project has estimated emissions of 100 tons per year of NOx, which requires 120 tons of ERCs. The current ERC bank shows 122 tons of NOx and 224 tons of VOC. Inter-pollutant trading of VOC for NOx is allowed at a 2:1 ratio, which means that there is an equivalent amount of NOx ERCs of 234 tons in the basin. Of these totals, 50 tons are optioned to PG&E and most of the rest are not for sale. Additionally, RACT adjustments have not been accounted for in the ERC totals. The typical turbine power plant has been controlled from a level of 225 ppm in 1970, to 42 ppm in 1973 (Rule 68), and 9-15 ppm using Best Available Retrofit Control Technology (BARCT) in 1997, which has lowered the need for ERCs. Potential sources of ERCs include overhauling existing sources, however District rules only allow this for same-site sources unless the source is shutdown prior to construction of the new source. The District currently exempts from permitting pre-1994 turbines under 1 MW and boilers less than 5 MMBtu/hr. Their experience indicates than the creation of MERCs is more expensive that the cost of obtaining conventional ERCs, even though the cost of conventional ERCs has increased five-fold in recent years.

Neil Pospisil, Calpine

Calpine has recent ERC/offset experience with their Los Medanos, Sutter Power, and Delta Energy Center Projects. All of these projects required ERCs during the permit process, and Calpine obtained necessary ERCs for each. This requires advanced planning. However, acquisition of ERCs can be compromised by regulatory uncertainties and the potential for the Energy Commission to require additional ERC mitigation beyond the requirements of the local air pollution control agency. Inter-pollutant trades have worked well for the Bay Area projects that Calpine has proposed. This has not been the case in other areas where ERCs have been required by the Energy Commission, but have not been required under air district regulations. Calpine's major concerns regarding offset constraints are the following: 1) there is a shortage in PM10 ERCs statewide; 2) uncertainty in the offset packages being proposed cause significant risk in the siting process; and 3) Calpine would suggest that projects be permitted using available ERCs plus mitigation fees in lieu of ERCs when no conventional ERCs are available. Answering questions from Commissioners Laurie and Pernell: 1) ERC availability is a critical factor that is considered by Calpine in the initial siting process for a new plant; 2) Calpine keeps records of ERC availability and uses them along with other siting constraints in their planning process; 3) ERCs are generally required in the areas with the highest current load demand and projects are also generally sited near the load demand due to all of the other siting constraints (i.e. gas lines, etc.); 4) mitigation fees would help a power project proponent in areas with limited offset options (i.e. Otay Mesa) 5) Calpine has had additional offset mitigation be required by the Energy Commission above that required by the local air pollution control agency and that mitigation has consisted of traditional ERCs; 6) the requirement for additional ERCs from the Energy Commission occurs during the normal certification process timeframe as allowed in AB970. Mr. Nazemi and Mr. Moore identified funding for the Carl Moyer diesel retrofit program as a potential way of using emission fees to create ERCs.

Steve Cohn, SMUD

The Sacramento area and SMUD's electricity demand is growing fast. SMUD currently has resources for ½ of the existing load demand. SMUD has added over 400 MW to their system over the last few years, a 44 MW peaker is currently being added, another plant is being upgraded to provide a reliable supply of 75 MW, and they are negotiating for up to 45 MW of wind power from Solano County. For the future, SMUD is looking to add a 500 or maybe 1000 MW gas-fired plant at the Rancho Seco site. Offsets are the most significant constraint in the Sacramento area and currently there are very few banked ERCs. In the area, over 80 percent of the emissions are from mobile sources, and they remain the greatest untapped source of future emission reductions. Traffic improvements could reduce mobile emissions and ease area congestion as well. SMUD would like to work with the Energy Commission and other agencies to make mobile source emission reductions a practical source for creation of ERCs. A new local program called SECAT is currently working to replace old diesel engines or vehicles in order to reduce emissions in the air basin. While putting money into programs like these for ERC creation is helpful, SMUD would encourage more creative options like funding transit districts to make improvements in their systems. It is clear that most transit districts need the money to improve services and that if transit services are provided they will be used. These kinds of solutions would not just improve air quality but would address other societal issues as well. Mr. Tooker noted that SMUD initially proposed a mobile offset program several years ago to provide offsets for a proposed powerplant. The proposed mobile offset program was subsequently stopped because the air quality agencies couldn't agree on the proposal. SMUD would look forward to try another mobile source offset program in the future.

Gail Ruderman-Feuer, National Resources Defense Council

Ms. Ruderman-Feuer indicated that conservation and use of renewable energy would reduce the power requirements and that no offsets are necessary for the creation of some renewable energy sources. Ms. Ruderman-Feuer agreed that there does appear to be a shortage of NOx ERCs in San Diego and PM10 ERCs in the SCAQMD, but there are sufficient offsets available in other areas. She was not sure that power plants need to be sited near the load centers. She expressed concern that the use of mobile source emission reductions is not legal, that they do not meet the five requirements (real, quantifiable, etc.), and that they need to provide years of emission reduction. She recommended that offsets be obtained from controlling existing sources, such as the many uncontrolled power plants in the SCAQMD. She suggested requiring all power plants be retrofitted to BARCT and allow the owners to sell the ERCs that are created. She noted that SCAQMD has documented the potential for 10,000 ton per year of NOx reduction using controls that would cost $3,100 per ton at the existing refineries and power plants in the SCAB. She suggested that since financial incentives do not seem to be enough to encourage retrofit, additional regulatory requirements should be put in place. The NRDC believes that the use of mobile sources to offset emissions should be a last resort and that mitigation fees are even worse. NRDC also believes that ERCs should be created in actuality prior to their use. NRDC is concerned about the executive orders recently enacted, and provided the Energy Commission with a position paper regarding these orders. NRDC has concerns regarding inter-pollutant trading as the technical basis for these trades are not proven.

PUBLIC COMMENT

Ann Simon, Communities for a Better Environment

Ms. Simon expressed concern that ERCs are used like pipes or any other commodity as a construction input to these projects and that they shouldn't be treated that way. Ms. Simon noted that the creation of ERCs without real benefit, just to create these construction inputs is not what should be considered. Ms. Simon suggests offsets not be treated as commodities in order to produce an actual air quality benefit. Ms. Simon believes that mobile ERCs used for stationary sources is not legal under federal law. Commission Pernell asked whether the scenario identified by Mr. Cohn of SMUD would be a viable scenario for mobile to stationary ERC use. Ms. Simon responded no it is not legal under the Federal CAA and the years of reduction are not consistent with the years of emissions from the new stationary source. Commissioner Pernell then commented that public transportation could be assumed to last 30+ years, to which Ms. Simon agreed that reducing pollution from mobile sources is beneficial on its own. Ms. Simon urged the Commission to consider emission controls at existing sites and to consider environmental justice during the siting process and consider the impact overburden that existing sites may have and identify more remote alternatives regardless of the efficiency issues.

Cindy Tuck, California Council for Environmental and Economic Balance

Ms. Tuck agreed that there is an emission credit availability problem. Ms. Tuck believes that the Energy Commission should not require ERCs above what is required by federal and local air quality regulations, and be careful about any additional project mitigation being required. Ms. Tuck noted that the EPA's RACT adjustment requirements stem from an internal memorandum and are not based in law and should be challenged. Ms. Tuck believes that the existing banking system gives companies responsibility for their emission reduction credits and that concerns regarding credit hoarding should not be used to force anyone to sell ERCs.

Mr. Nguyen of EPA then provided additional clarification of EPA's ERC RACT adjustment requirements.

Jim Martin, Environmental Defense Fund

Mr. Martin is concerned about NOx emissions. He notes that studies indicate that NOx is implicated in the formation of ozone, PM10, nitrate deposition and haze in Class I areas. Mr. Martin noted that unlike other pollutants, NOx emissions are increasing rather than decreasing, which is creating a problem. Mr. Martin suggests that care be taken in dealing with NOx emissions due to the increase in NOx related impacts

Mahesh Talwar, OceanAir Environmental

Mr. Talwar noted that the use of MERCs can be troubling but would like environmental groups to support actions that work. Mr. Talwar indicated that the Carl Moyer program was created under a state bill, and therefore, this program has commonality regardless of specific local agency acceptance. Considering RACT adjustments for ERCs, Mr. Talwar believes that ERCs are often RACT adjusted going into the process and should not be adjusted twice without careful consideration of double counting the adjustment. He stated that the values of ERCs and potential adjustments prior to sale should be known up front. Mr. Talwar recommended that the Energy Commission should not evaluate fine particulate matter (PM2.5) from powerplants until a federal standard for PM2.5 is enforceable.

John Grattan, Grattan and Galati

Mr. Grattan believes that the Warren Almquist Act's requirement that offsets be in place prior to certification is more stringent than most district regulations and federal law, and impedes quick certification and construction of needed power plants. Mr. Grattan suggested that offsets should only have to be identified and not acquired during the process, but be provided 30 days prior to operation. Commissioners Laurie and Pernell then questioned Mr. Grattan about whether financing could be completed without offsets, what would happen if offsets could not be obtained, and if operation should be allowed without offsets if problems occur? Mr. Grattan indicated that financing could be completed, the proposals would only go forward without offsets "in-hand" if the risk that offsets could not be procured was low, and that power plant should not be allowed to operate if offsets can not be found.

Mike Murray, Sempra Energy

Mr. Murray indicated that this discussion was invaluable, that this is a short-term and long-term problem, and that the forecasted 5000 MW shortfall this summer was real. Mr. Murray indicated that the 5000 MW short-fall could be met by 1) additional conservation, 2) interruptible power, and 3) expedited siting of new power projects while still meeting all regulatory requirements. Mr. Murray indicated that siting does in fact need to occur near load and power infrastructure for many reasons, although line loss is only significant when the distance is thousands of miles. Mr. Murray agrees that mobile source credits need to be made available and used for stationary sources and that inter-district trading is important.

Larry Allen, San Luis Obispo Air Pollution Control District

Districts are aware of the ERC shortage. CAPCOA will be conducting a study of this issue for power plants and other sources. The increased use of ERCs from new power projects will deplete banks and cause this to become a greater constraint that will effect other industries. ERC needs can be reduced by the use of more efficient control technologies (i.e. SCONOx). Additional ERCs can be made by controlling existing under-controlled facilities, but there may need to be some flexibility with regard to the timing of when these permanent ERCs are created. He suggested that applicants be required to look for existing sources to be controlled and control them if possible before using available ERCs. Unpermitted sources, such as agricultural pumps, should be identified and controlled. There is a concern that certain technologies being required, such as CO catalysts, have potential detrimental effects (i.e. increasing PM10 emissions) that should be addressed. ERC trading ratios are a concern and can be used to create ERCs in the most beneficial way, an example is giving more than 1 lb of ERC for 1 lb of diesel exhaust PM10 reduction due to the significant health effects of diesel exhaust. Conservation and renewable energy are important, and all of the new gas-fired plants being proposed may keep new renewable energy sources from being built.

PANEL 2: INNOVATIVE OFFSET SOURCES AND SOLUTIONS FOR LACK OF OFFSETS

Mohsen Nazemi, South Coast Air Quality Management District

Mr. Nazemi presented a summary of innovative offsets that have been proposed in the SCAQMD. To mitigate potential impacts from the proposed merger of SDG&E and SCE, it was proposed to retrofit agricultural pump engines with electric motors. The proposal was dropped when the merger fell through, however SCE eventually completed this project, which SCAQMD considered to meet the 5 ERC criteria (real, quantifiable, etc.). SCE received 75 tons of NOx ERCs that were limited to a ten-year lifespan (1993 to 2003), which were subsequently converted to NOx RTCs. SCAQMD considers MERCs to be an allowable method for ERC creation when they create emission reductions that are truly surplus. SCAQMD also believes that MERCs should have a limited lifespan. Retrofit of sources in SCAQMD is not practical as SCAQMD uses BACT emissions as the ERC creation threshold, so only shutdowns would result in any appreciable bankable emission reductions. SCAQMD currently has both area source and MERC emission reduction programs submitted for EPA approval. Without prior EPA approval, SCAQMD considers these types of programs to have significant risk (i.e. being disapproved late in the process).

Steve Moore, San Diego Air Quality Management District

Mr. Moore outlined the MERC program that was created for the proposed Otay Mesa project. SDAQMD identified that the 5 ERC criteria would have to be met in order for the program to go forward. The program consisted of replacing Heavy-Heavy Diesel and marine vessel engines with CNG and LPG engines. Issues addressed during the creation of this program included: 1) credits were necessary for the life of the project and the MERCs would have shorter timeframes; 2) the engines being retrofitted could be displaced by competitor vehicles; 3) local impacts from the project may not be adequately addressed by the MERCs. To deal with these concerns they limited the program to refuse collection trucks and marine vessels that were captive to San Diego County and had lives of 8-10 and over 30 years, respectively. During the process, EPA wanted to make sure that the program did not allow any backsliding, meaning that future replacement engines be at least as good as what they replace so emissions are always going down. CARB wanted to front-load the emissions reduction requirements so that the emission reduction for the shorter life-span vehicles would cover the entire 30 year emission obligation. This could be done by incorporating a discount factor for shorter lifespan vehicles. SDAQMD was in favor of the front-loading methodology as it created the emission reductions sooner rather than later, aiding in attainment goals. Additionally, both parties required significant record keeping by both the mobile source owner and the MERC user to ensure that the emission reduction requirements were continually being met. The MERC user is also responsible for any deficit that may arise from reduced vehicle activity. The program was limited to NOx ERCs only and does not allow inter-pollutant trading of these MERCs. SCAQMD believes the benefits of this program to be: 1) real emission reductions (as opposed to using credits from reductions that may have occurred years earlier) in excess of what you get normally in the NSR process; and 2) diesel toxic emission reductions. Drawbacks of this program include: 1) the limited scope; 2) the onerous record keeping requirements; 3) potential user liability;

4) cost (~$150,000/ton) and; 5) the real "surplus" reduction potential will drop as vehicles get cleaner in the future.

Duong Nguyen, EPA

Mr. Nguyen outlined EPA's current MERC point of view. EPA is currently determining how MERCs can be used in the long-term. MERCs may be allowed in future cases but only on a case-by-case basis. The SDAQMD case was conditionally allowed because it met all five ERC requirements, and the framework of that case will likely be used in future cases.

Gordon Hester, Electric Power Research Institute

Mr. Hester discussed how to make a state emission bank useful for power generators. The program the state will use to create and apply ERCs should meet the following criteria: 1) aid in the expedited permitting process and; 2) not compromise environmental objectives. In order to aid in the expedited permitting process, the ERC generation should be done where ERCs will be needed and in time for there use and be in areas that have access to fuel sources. In order to maintain environmental objectives: 1) ERCs need to be made available; 2) price of offsets should be a function of the emission rate or a function of the objectives of the Governor's executive order; 3) costs should also reflect control technology costs; and 4) the ERC costs should have certainty (i.e. be available at a known cost). The program should be kept simple or it won't be used.

Mahesh Talwar, OceanAir Environmental

Mr. Talwar noted that MERCs were used in Santa Barbara County in the early 1990s to provide CEQA mitigation for petroleum development projects. CEQA mitigation is unlike NSR offset requirements in that the 5 ERC criteria (real, enforceable, etc.) do not have to be strictly met. The SDAQMD MERC program was initiated over 2½ years ago and required a significant amount of time and money but eventually came to fruition. It takes time and money, to create these innovative solutions and the regulatory barriers are tremendous, so these kinds of innovative approaches may not be feasible in six months. Government regulation and programs are also in competition with private companies that want to create ERCs. The ERC banks that were healthy four years ago are now depleted, so innovative solutions are being considered. However, rulemaking may be necessary to allow these approaches and that will take time. Mr. Talwar recommended that the Energy Commission allow more liberal CEQA type approaches for offsets that they may require in addition to district requirements. Additionally, Mr. Talwar supports the proposed bill that will put all of the emission reduction credits created by government programs into a bank that can be used for power plant projects. Mr. Talwar also recommends encouragement or incentives for the use of alternative fuels such as bio-diesel or ethanol.

Ken Lim, Bay Area Air Quality Management District (BAAQMD)

Mr. Lim discussed the availability of ERCs in the Bay Area, noting that "on the books" there seems to be sufficient NOx and VOC ERCs; however, prices will increase due to reduced availability. PM10 is currently very constrained, however, most power projects do not trigger offsets under BAAQMD trigger levels for PM10. However, if this mitigation is considered necessary under CEQA by the Energy Commission then the availability of PM10 ERCs will be constrained. Mr. Lim indicated that a silver lining of the high offset cost is that it drives more efficient control technologies and creates an incentive for the creation of new ERCs. Mr. Lim believes that it is the offset issue that has driven the proposed NOx levels from 20 ppm to 2.5, rather than District BACT requirements. Mr. Lim also stated that the District has a community offset bank for small sources (i.e. <50 tons/year) and that the District has been receiving more inquiries regarding the process to create ERCs than at any time in the past.

George Poppic, California Air Resources Board (CARB)

Mr. Poppic indicated that CARB is in the process of reviewing the recent executive orders. Mr. Poppic indicated that one of these orders required CARB to create an offset bank for peaker power projects. He stated that CARB was determining how they could accomplish this, and that the Carl Moyer program is one potential method CARB may use to create ERCs. CARB is grappling with how to address the other executive orders that address the increasing power from existing plants, and expedited permitting of new plants. Answering Commissioner Laurie's question about ARB's role in determining if there are conflicting public policies, Mr. Poppic indicated that CARB is strictly limited to air quality issues and does not address larger public policy issues.

PUBLIC COMMENT

Eric Walthers, TRC

Mr. Walthers suggested that analyzing projects using a risk-based analysis/risk-based management approach could simplify the certification process and ensure the project meets insignificant impact goals. Mr. Walthers also believes that the Energy Commission should not impose mitigation above that required by local and federal law and that, in his experience, such additional mitigation is not required for other industries.

Mohsen Nazemi, SCAQMD

In response to a written comment from NRDC that noted that ERCs could be easily created through the retrofit or closure of existing power plants, Commissioner Laurie asked Mr. Nazemi to address the BACT-down provision of SCAQMD ERC rule. Mr. Nazemi indicated that he wanted to address other issues as well. Mr. Nazemi noted that revisions to the RECLAIM rules were being considered to let power plants get NOx ERCs outside of the RECLAIM NOx RTC trading program. However, ERCs generated outside RECLAIM in the basin are post-BACT emission reductions (this is due to an agreement with EPA regarding the current offset ratio of 1.2:1 that is allowed for the district); therefore, only shutdowns are likely to provide a potential for creation of new ERCs. Mr. Nazemi also noted that there are ongoing NSR reform actions occurring at EPA, which could change how ERCs are discounted. Mr. Nazemi also had other specific concerns including: 1) while regional pollutants require regional solutions and that localized impacts of a project should also be addressed. If the impacts are not significant then no additional consideration of disproportionate impacts under environmental justice should be made; 2) there should be a prioritization to clean up the oldest and highest emitting existing power plants with re-powered plants; and 3) SCAQMD is in favor of the concept of environmental dispatch.

Taylor Miller, Downey, Brand, Seymour and Rohwer

Mr. Miller wanted to make sure that the Energy Commission was aware that there is an offset problem in both Southern California and Northern California. Mr. Miller noted that cars and trucks are the majority of the air pollution problem so he suggested that the potential use of MERCs should be kept on the table.

Suma Peesapati, Citizens for a Better Environment

Ms. Peesapati was pleased to hear that there will be a future hearing on local issues that will include discussion on environmental justice issues. Ms. Peesapati noted that the power crisis may portend an environmental justice crisis. Ms. Peesapati believes that MERCs are not legal under Federal Law and the use of mobile source reductions may not address the environmental justice issue of local impacts. Ms. Peesapati noted that the Federal Clean Air Act's limitation of emission credits being obtained from stationary sources was meant as an economic incentive program for emission reductions and ERC costs should reflect control cost incentives. Ms. Peesapati was concerned that NOx and PM10 emissions are not air toxics and are not subject to the same localized impact restrictions as air toxics

Bill Chamberlain, Energy Commission Chief Counsel

Mr. Chamberlain expressed concern about the general lack of regulations for small emission sources with relatively low emissions. Mr. Chamberlain cited a shortage of low-NOx turbines that may cause project proponents to try to permit at higher levels which can't be appropriately sited and certified. Mr. Chamberlain expressed concern that if power demands can not be met it could cause a major increase in the use of small household generators, which have significantly higher emissions than the turbine projects that couldn't be sited.

George Poppic, CARB

Mr. Poppic noted that local air districts are fairly constrained in what they permit and what they can require in terms of mitigation. Mr. Poppic noted that the certification process should include assessment of all project impacts, including construction emission impacts, in order to determine necessary project mitigation for the project as a whole.

ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 1: What regulations require emission offsets and what criteria are used for approving emission offsets?

1. *Are emission offset air quality permitting requirements embodied in Federal Law? What are the federal, state and local requirements? How do emissions trading programs such as RECLAIM apply to new electric generating projects?*

   Yes, offset requirements are required in the PSD/NSR regulations of the Clean Air Act. Additionally, the State of California has offset requirements written in the

California Clean Air Act. The specific requirements vary based on the specific area's attainment status and State Implementation Plan (SIP) requirements proposed to meet the area's attainment goals. Areas with the worst air quality have the most stringent offset requirements. RECLAIM is a SCAQMD specific regulation that only currently applies to NOx emissions. There are no other similar programs or regulations known to exist for power plants in California.

2. *Do emission offset requirements apply equally for all projects in all locations?*

No, offset triggers and offset ratios are specific to each local air quality district and are dependent on the air quality attainment status. Some districts have no offset requirements and others have triggers as low as 4 tons/year. Offset ratio requirements can vary from 1:1 to 1:5 for like pollutant offsets and may be significantly higher for inter-pollutant or inter-basin offsets. The regulations governing the use of inter-pollutant and inter-basin offsets are also district specific and must meet specific federal criteria.

3. *How have emission offsets typically been generated? What do the evaluation criteria "real, quantifiable, permanent, surplus and enforceable mean"?*

Emission offsets have traditionally been generated by stationary source equipment shutdown or "over control".

Messrs. Nazemi, Nguyen, and Moore at various points in the workshop noted that real emission reduction means that there is an actual verified emission reduction not just on paper; that quantifiable means that there are records to quantify the emission reduction; permanent means that the emission reductions will generally last as long as the new project (i.e. 30+ years); surplus means that the reductions were not required under other regulations or SIP requirements; and enforceable means that the local and/or federal authorities can exercise control, by some means, of the emission reductions.

4. *Where are emission offsets currently available? How are emission offsets banked? How are emission reductions discounted before being banked and at the time of use?*

A full accounting of all district ERC banks was not available for the Workshop. However, the following district information was presented. The staff paper provided ERC bank information for SCAQMD, SJVAPCD, BAAQMD and SDAQMD. The San Joaquin Valley has the largest ERC bank and the Bay Area has sufficient ERCs for a few power plant projects. Most other areas have limited available ERCs. The South Coast Air Basin is running out of PM10 ERCs and San Diego has a very limited amount of VOC and NOx ERCs. Mr. Nazemi of SCAQMD and Mr. Moore of SDAQMD provided additional information regarding the status of their emission banks, including the status of the RECLAIM NOx RTC bank for SCAQMD.

ERCs are banked by application for each source being reduced similar to a permit application.

As noted by Mr. Nguyen, EPA requires ERCs to be RACT adjusted (i.e. discounted) at time of use, with the exception of ERCs from the SCAB, as noted by Mr. Nazemi, where ERCs have been created by post-BACT control and are not required to be RACT adjusted.

5. *How have emission offset requirements affected the licensing of recent electric generating facilities*?

   To date all certified projects have been able to get conventional ERCs for certification. Mr. Pospisil noted that the three projects they have submitted were able to obtain ERCs. However, recent projects still in review have either had to resort to unconventional offset measures, such as the use of MERCs, as noted by Mr. Moore, or are still looking to find offsets for certain pollutants (i.e. PM10 and SO2). This problem will become more common as ERC banks continue to be depleted.

6. *What is the current and long-term availability of emission offsets? How will the long-term availability of emission offsets affect licensing of electricity generating facilities?*

   The current availability of offsets is limited in most areas of the state and the long-term availability will likely be more limited than current availability. The lack of ERCs for offsetting projects could limit the number of new gas-fired projects that can sited in the state.

Issue 2: What measures could be implemented to increase the availability of emission offsets?

1. *What innovative sources of emission offsets could be pursued?*
   a. *Area source emission reductions?*

      This issue was briefly discussed by Mr. Nazemi in the context of NOx emission reduction credits that were obtained through the replacement of agricultural engines with electric driven motors. SCAQMD considered this method to meet the five criteria for ERC creation (real, quantifiable, etc.) and 75 tons of NOx ERCs were issued, but these ERCs were only given a ten-year (1993 to 2003) lifespan. This process was considered feasible but was not completed as the project it was going to be used for was canceled. Additional discussion of road paving indicated that this method was viable for the creation of PM10 ERCs. Therefore, it would appear that area source emission reductions could be pursued, provided regulatory requirements can be met..

b. *Mobile emission reduction credits?*

The use of MERCs is currently being implemented for the Otay Mesa project. EPA approved the program for this site. Mr. Moore provided details on how the garbage truck and marine vessel engine retrofit/replacement program was going to be implemented. Mr. Nguyen indicated that EPA would only approve this type of ERC on a case-by-case basis. Therefore, it would appear that MERCs may by a viable option for creating ERCs. However, Mr. Moore also indicated that the expense of creating MERCs was much higher than the expense for traditional ERCs (~$150,000 ton).

However, it should be noted that a couple of the public commenters stated that they believe that the use of MERCs is not legal under the Clean Air Act.

c. *Agriculture emission reductions*?

Other than the proposed agricultural pump engine replacement discussion by Mr. Nazemi, this topic was not specifically addressed by the panelists.

d. *Currently unregulated emission source reductions*?

As noted above, other than Mr. Nazemi's discussion of the proposed agricultural pump engine replacement, this topic was not specifically addressed by the panelists.

e. *Inter-pollutant emission reductions?*

The use of inter-pollutant emission reductions was noted to have occurred and is a currently viable means of emission offsetting where allowed. It was noted that inter-pollutant offsets are generally only allowed in pre-cursor compounds such as NOx for VOC when offsetting to provide mitigation for Ozone impacts, or NOx or SOx when offsetting for PM10 impacts.

f. *Inter-basin emission reductions*?

The use of inter-basin emission reductions can be used, but as indicated by Mr. Nguyen and Mr. Nazemi, this method of offsetting can only be used in downwind areas where the air quality is worse than in the upwind area where the ERCs are being obtained. Methods used to calculate appropriate offset trading ratios are complex and often disputed when applied to individual projects.

g. *Other*?

No specific other methods of creating ERCs was discussed by the panel.

2. *What are the limitations to using or obtaining emission reductions from any of the above?*
   a. *Are there regulatory limitations?*

      There are regulatory limitations on all ERC creation and use regardless of the source. As noted by Mr. Nguyen, ERCs have to meet the five criteria and specific uses such as MERCs, are only approved on a case-by-case basis.

   b. *How difficult and costly is it to apply these control strategies?*

      As noted by Mr. Talwar and Mr. Moore it can be a very difficult process to create non-traditional ERCs, the costs can be significantly greater than the creation of traditional ERCs, and burdensome record keeping requirements may be required.

   c. *What needs to be done to ensure that these reductions are real, quantifiable, permanent, surplus and enforceable?*

      Mr. Nguyen noted that the EPA will be the final arbiter on whether proposed ERCs meet the above criteria. Mr. Talwar suggested that all parties get together early in the process to make agreements on the viability of specific proposed innovative approaches to create ERCs.

   d. *Are there other methods of ensuring air quality impacts from power generation are mitigated? What federal, state, or local actions would be required to implement these measures?*

      This topic was not specifically addressed in the workshop. It does not appear that methods other than providing federally enforceable ERCs for federal offsets are viable. However, as noted by Mr. Talwar it is possible for the Energy Commission to use more liberal criteria for emission mitigation when required under CEQA.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

1. It is recommended that Air Pollution Control Districts examine temporarily opening their respective ERC "priority reserves", if any exist, for the permitting of power plants to meet the current electricity shortfall when traditional ERCs are not available. It is further recommended that a fair market price be paid for the use of "priority reserve" ERCs.
2. It is recommended that representatives from local agencies, CARB, Energy Commission and EPA meet to determine feasible and legal ways to create ERCs.

3. It is recommended that Energy Commission, with the help of local districts, compile a list of high polluting power plants to be identified for potential control technology retrofit, and that the potential ERCs from such retrofit be identified.
4. It is recommended that Energy Commission should complete an updated offsets availability report in consultation with the local agencies to provide all parties information on the current status of local ERC banks and identify all regions that are currently constrained.
5. The Energy Commission should not require that measures required under CEQA necessary meet the Federal NSR offset requirements of being real, quantifiable, permanent or surplus, but rather that the measure have a substantial likelihood of eliminating or lessening the impacts of the project.
6. It is recommended that the Energy Commission discourage the hoarding or speculative accumulation of ERCs and encourage the Air Pollution Control Districts to find means that would allow new projects to be able to find and acquire banked ERCs.

LAND USE, LOCAL AGENCY & PUBLIC PARTICIPATION WORKSHOP SUMMARY

INTRODUCTION

In the morning of March 8, 2001, the California Energy Commission (Energy Commission) conducted the Land Use Issues Workshop to discuss land use review procedures, local land use plans and local agency participation that affect the licensing of future powerplants by the Energy Commission. A volunteer panel, comprised of members of local agencies and energy industry representatives, discussed land use issues associated with powerplant licensing, information needed to develop appropriate actions, and the methods to avoid land use constraints to the licensing of future powerplants.

In the afternoon of March 8, 2001, the California Energy Commission (Energy Commission) conducted the Local Agency and Public Participation Workshop to discuss public and local agency participation in licensing future powerplants by the Energy Commission. A volunteer panel, comprised of members local agencies, intervenors and the electricity industry, discussed the information needed to facilitate public local agency participation, and develop appropriate actions, if any, to improve the Energy Commission licensing procedures.

OVERVIEW OF THE MORNING PANEL ON LAND USE

In opening comments, Commissioners Laurie and Pernell explained the purpose of the morning Workshop was to gather as much information as possible to examine potential barriers to long-term licensing of powerplants.

STAFF PRESENTATION

Eileen Allen, Supervisor for the Energy Commission’s Land and Traffic & Transportation Unit, provided an overview of land use and powerplant siting issues that the state is currently evaluating. Mr. Patrick Angell, of Pacific Municipal Consultants summarized the staff’s overview entitled “Land Use Issues That May Affect Siting New Powerplants In California”, dated February 22, 2001. Mr. Angell’s summary included: 1) description of land use considerations currently evaluated as part of the Energy Commission’s powerplant review; 2) description of applicable provisions of the Warren-Alquist Act related to laws, ordinances, regulations, and statutes (LORS) of local jurisdictions; 3) discussion of environmental justice considerations; and 3) discussion of land use constraints associated with land use compatibility, infrastructure requirements (e.g., extension and expansion of services), and compatibility issues with urban and rural sites. Mr. Angell stated that land use issues can vary widely depending on the local jurisdiction and the site in question, and that land use constraints also involve issues associated with compliance with applicable land use LORS. The level of participation of the local agency in the licensing powerplant process also varies.

Finally, a series of recommendations for improving the way in which land use issues are addressed in a siting case were identified in the paper, which included the following:

- Establish an early agency consultation process with local, regional, state and federal agencies potentially affected by a proposed powerplant project in order to identify land use and LORS issues prior to completion of the data adequacy process for applications for certification (AFCs). This process could also be used to identify alternative powerplant sites considered acceptable by the affected agencies.
- Provide workshops or information sessions for affected land use agencies regarding how the Energy Commission powerplant permitting process works and how the agency can provide input.
- Offer assistance to local and regional agencies in the development of programs that identify power needs on a regional basis (e.g., Sacramento Metropolitan area) as well as land areas appropriate for siting powerplants and related linear facilities.
- Encourage local land use agencies to consider power needs of the community in their land use and planning activities (e.g., general plan and specific plan development processes and associated zoning ordinances).

MS. ROSEANNE CHAMBERLAIN, EL DORADO COUNTY LOCAL AGENCY FORMATION COMMISSION

Ms. Roseanne Chamberlain provided a presentation outlining the powers and duties of Local Agency Formation Commissions (LAFCOs) and how LAFCOs and the Energy Commission's powerplant licensing process may interface. Ms. Chamberlain identified that LAFCO is generally a boundary regulatory commission and is likely the most misunderstood government agency in the state. LAFCOs have only indirect land use authority and it has substantial planning powers that it administers through spheres of influence and regulation of service provider agencies. LAFCOs are a small piece in regulation of land uses. However, they could have a significant role in powerplant licensing, if the adequacy of services to be provided by local agencies (e.g., wastewater and water supply) to support a powerplant are at issue. Ms. Chamberlain noted that a frustrating issue for LAFCOs is that California Environmental Quality Act (CEQA) environmental documents on development projects often do not address LAFCO actions, which make these environmental documents unusable by LAFCO. LAFCO's review powers and authorities were expanded in 2000 under AB 2838. LAFCO actions now require consideration of water supply, which could impact powerplant licensing. Government Code Section 56434 provides for cooperation among LAFCOs across county boundary lines to address public service provision issues that could come into play on a powerplant project. Ms. Chamberlain identified that LAFCOs should be included early in the powerplant licensing process.

As part of Ms. Chamberlain's presentation, she identified some circumstances under which the State should consider legislation such that the Energy Commission should provide "special status" for LAFCOs, when commenting on proposed LAFCO actions that may impact powerplant siting. Ms. Chamberlain also identified that there are a number of bills associated with improving the electrical supply situation in the State that would streamline and improve the LAFCO process, as well as a desire for the State to clarify LAFCO's role in considering and cooperating on powerplant projects.

Commissioner Pernell asked about potential LAFCO involvement in powerplant licensing and whether LAFCOs have ever intervened on a powerplant project. Ms. Chamberlain identified that LAFCOs would be concerned with service provision and that LAFCOs have been involved on powerplant projects under the Energy Commission.

MS. YVONNE HUNTER, LEAGUE OF CALIFORNIA CITIES

Ms. Yvonne Hunter identified that local land use control is sacred to cities and counties and identified initial concerns of the League regarding AB 9x associated with the designation of powerplant sites. She provided a summary of an article from the Sacramento Bee dated January 28, 2001 regarding the impression that local agencies were to blame for delays on new powerplant licensing. Ms. Hunter identified that local agencies are not solely responsible. Ms. Hunter also expressed concerns regarding potential consideration of amending Section 25525 of the Warren-Alquist Act to delete the requirement that a project conform to local or regional LORS.

Regarding Workshop Question, Issue 1 (What land use issues potentially constrain energy development in California?), Ms. Hunter responded that it has not been the role of local agencies to plan for energy facilities, and that, that responsibility has generally been the Energy Commission's pursuant to the Warren-Alquist Act. Ms. Hunter did not feel that the inclusion of energy elements in a general plan was appropriate and that general plans already include provisions for energy siting as part of land use designations and zoning. She also identified that environmental justice issues are relevant for the Energy Commission to consider, but vary from land use issues and tend to be more complicated.

Regarding Workshop Question, Issue 2 (Are sufficient avenues available to the public and local agencies to provide input to the process?), Ms. Hunter said that local agencies are willing to work in conjunction with the Energy Commission on powerplant projects and that the Energy Commission needs to educate local agencies on the powerplant licensing process. Ms. Hunter recommended that the Energy Commission conduct community forums to educate local agencies. Ms. Hunter identified that there appears to be sufficient avenues for local agencies to provide input into the powerplant licensing process. However, she expressed concerns regarding proposed SB 28x that would limit the amount of time public agencies can comment on powerplant projects. Ms. Hunter also identified that there are differing land use issues associated with powerplant siting in urban areas versus rural areas.

Regarding Workshop Question, Issue 3 (What measures could be implemented to address issues earlier in the application process or to assist applicants in addressing public or local agency concerns?), Ms. Hunter identified that it is the Energy Commission's responsibility to educate applicants to understand the process in California, including local land use control.

MR. GREG FUZ, CITY OF MORRO BAY

Regarding Workshop Question, Issue 1 (What land use issues potentially constrain energy development in California?). Mr. Greg Fuz provided a brief overview of the coordination that has occurred between the City of Morro Bay, Energy Commission staff and the applicant for the Morro Bay Project. Mr. Fuz identified that the City of Morro

Bay considers early coordination between local agencies, the Energy Commission and the applicant to be critical to a successful process. This early coordination involved development of a reimbursement agreement between the City and the applicant to provide the City with the resources necessary to adequately participate, as well as, a pre-application process to address issues between the City and the applicant.

Regarding Workshop Question, Issue 2 (Are sufficient avenues available to the public and local agencies to provide input to the process?) and Issue 3 (What measures could be implemented to address issues earlier in the application process or to assist applicants in addressing public or local agency concerns?), Mr. Fuz identified that reimbursement agreements between local agencies and applicants, as part of a pre-application process, would be helpful in addressing local issues through the Energy Commission. He recommended that the Energy Commission consider a policy and/or encourage applicants to establish reimbursement agreements with local agencies. Mr. Fuz identified that a local agency's role in the Energy Commission licensing process is unclear (e.g., are local agencies advisory to the Energy Commission? What is the appropriate time for local agencies to inject themselves into the process?). He recommended a public agency ombudsman or an assistant to the Public Adviser to focus on public agency coordination. Mr. Fuz also recommended that some sort of incentives program be provided to local agencies to assist in licensing of new powerplant projects.

Mr. Fuz also identified that powerplant projects can result in direct and indirect social and economic impacts, such as: 1) the loss of tourism, construction impacts, housing and public service impacts dye to worker relocation.

MR. TOM LAST, SUTTER COUNTY

Mr. Tom Last described Sutter County's concerns regarding the Energy Commission's powerplant licensing process based on the County's experience with the Calpine Sutter County powerplant project. Mr. Last's comments generally related to Workshop Question, Issue 2 (Are sufficient avenues available to the public and local agencies to provide input to the process?) and Issue 3 (What measures could be implemented to address issues earlier in the application process or to assist applicants in addressing public or local agency concerns?). He expressed concerns regarding the number and format of meetings that the Energy Commission conducts on powerplant projects. The "trial" format of meetings and workshops tend to be intimidating, confusing and hostile for the public. Mr. Last identified that the format of the meetings appears to require attorneys that the public and local agencies often can't afford. He recommended that the meetings be fewer and more informal and that the process be modified to provide clear periods when comments are received to force participants to focus their comments.

He expressed concerns regarding manipulation of the licensing process by groups that do not have actual land use or environmental concerns. Mr. Last also identified issues associated with coordination with other permitting agencies and the timing associated with receiving their approvals. He recommended that coordination should occur with federal agencies to ensure process streamlining occurs at all levels.

Mr. Last identified that during the processing of the Sutter County powerplant project, there were difficulties coordinating with the Energy Commission project manager and Energy Commission staff. He identified that the project manager did not appear to have control over the analysis provided in the staff assessment (the accuracy of this statement was verified during the morning Workshop). This caused problems when the County believed that Energy Commission staff misinterpreted the local ordinances of the County.

Mr. Last identified timing issues associated with completion of the powerplant licensing process by the Energy Commission and local agency land use approvals that require the use of the Energy Commission's environmental document. He recommended that the Energy Commission consider developing an agreement with the local agency that specifies how the Energy Commission and local agency approval process will work upon receipt of the application.

Regarding siting issues, Mr. Last identified that the Energy Commission should consider providing incentives to those applicants and/or local jurisdictions that have potential powerplant sites, but inadequate infrastructure facilities to serve it.

DR. PETE MASON, CALPINE/BECHTEL

Dr. Pete Mason summarized issues associated with powerplant siting, generally related to Workshop Question, Issue 1 (What land use issues potentially constrain energy development in California?). He provided an overview of powerplant siting work that an applicant typically does and how that work is incorporated into the application to the Energy Commission. Dr. Mason identified that fuel source, water source, connection to the transmission system and environmental justice issues are key items to consider for powerplant siting. He specifically identified land use as a "bedrock" issue as to whether a community wants a project. Dr. Mason identified that powerplant projects are often caught up in larger growth and development issues that are occurring statewide.

Regarding local land use regulations, Dr. Manson expressed the opinion that it is not necessary for a local agency to have specific development standards and zoning for powerplants, and that design issues are best worked out with each project. He also identified that powerplant siting associated with urban versus rural areas is also a challenge given typical concerns in existing urban areas and the effect of urbanization of rural areas.

Dr. Mason recommended working with local agencies on powerplant proposals prior to submitting an application to the Energy Commission. He also recommended identifying potential powerplant sites that have adequate infrastructure, have minimal land use constraints, are buffered or protected from future land uses conflicts, and to use existing brown-field sites for powerplant development.

PUBLIC COMMENT

Mr. Joe Rowley, Sempra Energy Resources

Mr. Rowley expressed support for the concept of having the Energy Commission use existing environmental impact reports (EIR), which address environmental issues associated with a powerplant site. Mr. Rowley stated that the goal should be to avoid redundancy and streamline the process.

SUMMARY OF THE ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 1: What land use issues potentially constrain energy development in California?

1. *What actions does the Energy Commission need to take to address land use conflicts?*
   a. *Are the State energy needs addressed in local land use plans?*
   b. *Should local general plans incorporate energy elements that contain policies that facilitate the siting of energy infrastructure?*

   While cities and counties are not required under State Planning and Zoning Law (Government Code Sections 65000 *et al.*) to provide energy elements or ordinances in their general plans or land use regulations, there are no state laws or standards that restrict such actions. Some local agencies do consider and plan for energy facilities in their jurisdictions. Local agencies have the ability to develop land use plans and development standards to consider and facilitate energy needs. During the morning Workshop, Ms. Hunter of the League of California Cities expressed the opinion that requiring energy elements as part of general plans was not appropriate. Dr. Mason from Calpine/Bechtel identified that the provision of specific development standards for powerplants may not be appropriate and was best addressed at the project-specific stage.

2. *Can the Energy Commission rely on local general plan environmental reviews as the bases for conclusions in siting cases?*

   Depending on the level of detail and age of local agency environmental documents, some analyses provided in local agency general plan EIRs and other environmental documents can be utilized in considering powerplant siting. However, this needs to be considered on a case-by-case basis. Some issues, such as agricultural land loss, may have been already adequately addressed and need not be addressed again by the Energy Commission. Mr. Rowley, from Sempra Energy Resources supported the use of local agency environmental documentation as a way to streamline the process.

3. *How can general plan amendments, zoning changes and variances required for energy projects be expedited?*

   Local agency land use actions associated with powerplant projects could be expedited. However, the ability to expedite would be on a case-by-case basis and would need to be negotiated with the affected local agency. Early coordination with local agencies was suggested by Mr. Fuz, Mr. Last and Dr. Mason.

4. *How can the State's need to ensure reliability of the energy system be balanced with local control over land use decisions?*

As identified in the staff paper “Land Use Issues That May Affect Siting New Powerplants In California”, February 22, 2001, and by the panel members, pre-application/early consultation with local, regional, state and federal agencies should be conducted to identify and resolve issues prior to the formal submittal of applications to the Energy Commission. Such early consultation would streamline the process. Other recommendations identified in the staff paper and by the panel members include: clarifying the ability of local agencies to enter into reimbursement agreements with applicants;; outreach specifically to local agencies to assist them understand the licensing process; and coordination with the Energy Commission and the local agencies in identifying and designating desirable sites for powerplants.

5. *Is there a need for long-term planning for energy facilities?*

Energy facilities are as essential to cities and counties as are water supply and wastewater facilities. Given the current and the expected long-term growth in the state, there is a need to consider long-term planning for energy facilities. However, unlike water supply and wastewater facilities and services that are typically considered by a local or regional agency, consideration of electrical service facilities varies widely throughout the state. In addition, powerplant projects are approved by both the Energy Commission (over 50 megawatts) and local agencies do not have prior knowledge of where or when these project may be proposed.

Given these conditions, there is no current coordinated approach statewide to plan for future energy demands. As identified in the recommendations of the staff’s land use issue paper, the Energy Commission should consider offering assistance to local and regional agencies in the development of programs that identify power needs on a regional basis as well as identify land areas appropriate for energy facilities.

OVERVIEW AFTERNOON PANEL ON LOCAL AGENCY AND PUBLIC PARTICIPATION

The local agency and public participation component of the workshop was conducted in the afternoon of March 8, 2001. No issue paper had been prepared specifically for the local agency and public participation issue area, and no formal staff presentation was made.

MS. ROBERTA MENDONCA, ENERGY COMMISSION PUBLIC ADVISOR

Ms. Roberta Mendonca, the Energy Commission’s Public Advisor, stated that the position of the public advisor was created by the Warren-Alquist Act. The Public Advisor does not have a role as a decision maker, nor is the position created to provide technical analysis. Ms. Mendonca said that the Public Advisor position was established to provide members of the public with an understanding of the process, timing of the licensing process, and direction as to where they might focus their energy to make their comments most effective. Ms. Mendonca stated that the Energy Commission decisions have been better as a result of the public's participation and comments. This is true both with regard to general issues, as well as technical issues. Intervenor comments have, in the view of Ms. Mendonca, improved projects by encouraging a voluntary change in the type of cooling, a change in project footprints, and through the monitoring of air quality.

Ms. Mendonca distinguished between intervenors that may have legal counsel, and public participants who are not presented by legal counsel. The number of public appears to increase in siting cases in urban areas. The issues that the public are most concerned about in siting cases include water, air quality, and public health. In the more urban and smaller communities, visual resources and noise are also important. In urban areas, the public believes there may be preexisting toxic conditions that will affect public health, and that a new project will only make conditions worse. Ms. Mendonca said these issues were generally reviewed as part of the Energy Commission's staff environmental justice analysis.

Those who participate in siting projects include neighbors, people looking for a job, neighborhood groups, or public interest organizations, such as the Sierra Club or Audubon Society. Sometimes the participant is an environmental watchdog group, or community action groups, such as Communities for a Better Environment, or SAGE. In some cases, a local community will participate, and sometimes intervene. In one case a state agency, the Department of Parks and Recreation, intervened.

Ms. Mendonca identified that improvements in the noticing process could improve public participating in the process. While a legal notice is required to landowners within certain distances of the site or linear facilities, there may be a far larger group of people just beyond that boundary that believe they may be indirectly impacted by the project or have other interests in the approval of the project. Ms. Mendonca also noted that the number of people provided notice may not correspond to the level of controversy on the case. In one instance she noted, a very contentious case had a mailing list of 52 people, while a non-controversial case had a mailing list of 4,000. The noticing requirements should be refined to ensure the public potentially directly and indirectly affected by the project are noticed. Ms. Mendonca said that the most frequent complaint from the public is that they had not heard about the project prior to the hearings or final decision.

The Public Advisor has initiated a program to provide siting case materials in public libraries. The Energy Commission is required to send a copy of the Application for Certification to five libraries throughout the state, and, in addition, such materials are provided to local libraries. The Public Advisor has also undertaken efforts to train library personnel in internet skills to enable them to access the Energy Commission materials online. Videos would be of assistance, and the Public Advisor has also made efforts to translate Energy Commission materials into Spanish to facilitate communication.

While Ms. Mendonca did not believe that the number of meetings held in licensing proceedings was an impediment to public participation, she suggested that the agenda and hearing process be modified to ease such access. Allowing public comment at the beginning of the hearing, and scheduling certain matters on a time certain basis, would be positive steps.

MR. TED JAMES, KERN COUNTY

Mr. Ted James indicated he had extensive experience with the Energy Commission staff in dealing with siting issues related to power plants, and views the relationship as very good. He noted that Kern County has a strong economy based on oil and gas production, with a lot of cogeneration activity. Kern County has large rural, undeveloped areas, and the majority of the power plants have been located away from urbanization.

Mr. James confirmed earlier workshop comments regarding the importance of local government and their ability to manage their own land use affairs. Mr. James commented on a partnership approach as being desirable. Mr. James expressed concern that recent efforts by the Energy Commission to expedite the siting process could backfire if the public were to perceive that corners were being cut. He felt this could be avoided by a greater emphasis on local issues in Energy Commission documents. Siting proceedings should be sensitive to local concerns, including issues usually raised through the CEQA process. Local zoning or general plan programs should also be dealt with during the hearing process.

Mr. James recommended that Energy Commission staff be encouraged to use local government's knowledge of land use issues and the identity of special interest groups. Involving local government at the early stages of the siting process would help to focus the applicant's attention on such issues. Of special concern to local agencies is the impact on neighboring land uses. Public access is one example of an issue that can be dealt with by the local agency. Forums to assist Energy Commission staff in understanding local issues, as well as assisting local governmental staff in the understanding of Energy Commission processes, would also be worthwhile.

Mr. James said that local governments are impacted by the issues raised during the siting proceedings and by requests for information from the applicant, staff and intervenors. Mr. James expressed concern that the staffing needed by the local agencies may not be adequate to respond effectively during the siting proceedings. Grants to local agencies to provide appropriate staffing should be considered. Early funding to support early meetings between the local agency and applicants and Energy Commission staff would also be helpful.

Mr. James encouraged the Energy Commission to use the local agency input when developing stategies for public participation. He also suggested that delegating some or all of the environmental review to the local agency, with appropriate funding and indemnification, could be explored, perhaps through a local equivalent certification program. Mr. James encouraged the Energy Commission to rid the siting process of reviews redundant to local agency actions. Review by two or more governmental agencies regarding the same issue takes time. Mr. James suggested that the Energy Commission support the establishment of mitigation cookbooks, which would clearly identify the applicant's responsibilities, and identify the alternative methods of mitigating impacts.

MS. KATHLEEN LIVERMORE, CITY OF FREMONT

Ms. Livermore stated that the City of Fremont has various interests in siting cases. These include the City's interest in keeping residents and businesses informed of the proposal and in seeing that uninterrupted power is provided.

Ms. Livermore expressed concern in situations where a site is proposed in one community, but an alternative site is identified in Energy Commission documents in another. Ms. Livermore was concerned that the analysis she reviewed did not clearly or adequately explain the potential constraints to developing the alternative site. She believed that staff alternatives analysis was misleading, but did not recommend the City of Fremont file formal testimony in response to staff's testimony, since staff's testimony could not be used to approve a project in Fremont.

Ms. Livermore stated that providing notice to local residents and interest groups is something the local agency is well positioned to undertake. The City has identified public interests and local interest groups as a result of work on other projects in its jurisdiction. While a simple ad in the newspaper may satisfy the minimum legal requirements, it will not reach the same network of individuals that might be contacted by the local agency.

MR. CHRISTOPHER ELLISON, ELLISON & SCHNEIDER

Mr. Christopher Ellison is an attorney who indicated he previously worked at the Energy Commission, and is now engaged in private practice, representing applicants before the Energy Commission. As one of those who was present at the Energy Commission when the public participation process was developed, Mr. Ellison indicated there were four primary goals: (1) Inform the decision maker; (2) Provide a fair opportunity for public comment; (3) Provide a timely decision; and (4) Promote public understanding and acceptance of the decision eventually rendered.

Mr. Ellison said that the one-stop process provided for by the Warren-Alquist Act is a unique process. While he does not believe the process is broken, he suggested that current process might not best serve the public. He said that the public is far more familiar with local agency processes including hearings before the planning commissions and hearings on Environmental Impact Reports. This contrast the far more legalistic process followed by the Energy Commission, which includes the taking of sworn testimony and cross-examination of witnesses. Consequently, the public prefers the local agency processes since they are more familiar. The Energy Commission process, from the lay person's perspective, requires an enormous investment of time. Mr. Ellison suggested that the Energy Commission consider a change to a process closer to the notice and comment process followed under CEQA. Mr. Ellison indicated that the Energy Commission process sometimes promotes feelings by people that they are aggrieved. The process itself, according to Mr. Ellison, sometimes deters communication, and fails to identify the public benefits to be achieved by the project.

MR. GREG FUZ, CITY OF MORRO BAY

Mr. Greg Fuz indicated that early consultation with the local agency to identify any fatal flaws in a project would be very beneficial. Mr. Fuz said that the local agency has substantial resources that it can use to assist the Energy Commission to identify local interest groups in the community, and provide notification of project events to these groups. Providing adequate resources for early local agency participation would enable the local agency to work with the Energy Commission to involve stakeholders in the process. The local agency could organize public involvement in siting cases, as well as provide critical review of development issues and evaluate proposed mitigation strategies. Such a process would assist in setting the project in the right direction early in the process. In Morro Bay, this was done through a memorandum of understanding between the City and applicant that identified key goals and common interests. The public process involved over a dozen meetings. The City also followed a pre-application process, and sponsored an advisory ballot measure. This was all done prior to the filing of the AFC.

Mr. Fuz identified several issues in which other local agencies were involved in the decision-making process. He suggested that, with the City's experience in dealing with such agencies, the city could act as a liaison to the Energy Commission staff in communications with such agencies, including the Coastal Commission. Following certification, Mr. Fuz indicated the City is in an ideal position to follow up with the monitoring program and permit compliance.

MR. MARK WOLFE, CALIFORNIA UNIONS FOR RELIABLE ENERGY (CURE)

Mr. Mr. Wolfe commented that the trial-like process followed by the Energy Commission has benefits. Mr. Wolfe stated that he believed the public has a meaningful role in the current process, and that the process also provides an avenue for participation by other groups, such as CURE. Mr. Wolfe stated that the current crisis should not result in a curtailment of the public participation process.

PUBLIC COMMENT

Ms. Joan Wood, Farm Owner-Sutter County

Ms. Joan Wood identified herself as a small farm owner in Sutter County. Ms. Wood indicated she had not received notification of the Sutter Power Project from the Energy Commission. She said she had been informed that representatives of Sutter Power had entered into conversation with the county two or three years before the certification process started. She said she felt that the parties had already agreed that the project would be built on the proposed site prior to her receiving knowledge of the powerplant. She encouraged the Energy Commission to provide adequate notice to those landowners that would be affected directly and indirectly by the project. Ms. Wood also questioned whether the urban effects of a power project on farming interests are adequately considered in siting cases.

Dr. Pete Mason, Calpine/Bechtel

Dr. Pete Mason said that the Energy Commission process is basically sound. The decisions result from a clear, objective process. The process enables the disclosure of the facts of the case, which then becomes the basis for the decision. Dr. Mason suggested discussions with the Nuclear Regulatory Commission might be helpful.

Christopher Ellison, Ellison & Schneider

Mr. Ellison suggested that the Energy Commission may wish to compare its licensing process to similar licensing processes in other states or elsewhere. While the Energy Commission process may be considered long and complicated, litigation tends to be limited.

Mark Wolfe, California Unions For Reliable Energy (CURE)

Mr. Wolfe suggested that the Energy Commission licensing process avoids local agency political issues that can impact the process.

ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 2: Are sufficient avenues available to the public and local agencies to provide input to the process?

1. *What are the key concerns expressed by the public and local agencies?*

   The public has concerns with environmental or health related issues such as air quality, water quality, public health, visual and noise. In general, it seems that the process is not like public participation efforts of local agencies and is unfamiliar. Local agencies expressed a concern that the existing process does not allow for their early involvement or advise regarding local issues and interest groups.

   a. *Does geographic location, rural versus urban environments, local demographics or size of municipality influence the type or nature of questions/concerns?*

      Based on the workshop presentations, the speakers did identify some differences between the rural versus urban environments with regard to population size. One speaker noted that more members of the public attend public meetings in urban areas because of the higher concentration of people affected by the project.

   b. *Do comments that are made by individuals, intervenors, and agencies specifically address the proposed power plant or do comments address broader issues (e.g., indirect impacts of a project, or community land use development concerns)?*

      Speakers did not specifically address this question. There was some discussion however with regard to comments providing valid input into the decision-making process. It does appear from the comments that some of the comments made by the public represent indirect impacts of the project.

   c. *Have* local agencies and public comments resulted in projects that better address community concerns and objectives?

      See response to (b) above. In general, comments made by intervenors have resulted in better projects that better address community concerns.

2. *At what levels can the public and local agencies participate?*
    a. *Who typically participates and what is their level of interest*?

    Environmental interest groups, community interest groups, local agencies and members of the public.

    b. *Does geographic location, rural versus urban environments or size of municipality influence the level of involvement or participation by either the public or local agencies?*

    Geographic location, rural versus urban or size of municipality does not influence the level of involvement. There is a general high level of interest for energy projects and the area they will serve.

Issue 3: What measures could be implemented to address issues earlier in the application process or to assist applicants in addressing public or local agency concerns?

1. *What mechanisms are available to identify issues of concern early in the application process?*
    a. *More defined plans at pre-application meetings?*

    Some of the speakers suggested that more information early on about a project and involving local agencies and the public at an early stage in the project would result in better projects.

    b. *Should the Energy Commission conduct community meetings early in the process to educate agencies and the public on the process and to scope issues regarding approval of the project?*

Yes. Early involvement of local agencies and the public would be beneficial to all parties.

    c. *Should the Energy Commission conduct program-level siting studies to assess potential concerns from local jurisdictions?*

While a program-level assessment was not specifically identified there was some discussion about involving local agencies at an early stage to identify local interest and concerns regarding the project and strategy on the best approach for public involvement. In addition, there was a suggestion that partnering with a local agency would be a good approach.

2. *How can the process be made accessible to the public and agencies, and ensure that their comments and concerns are addressed expeditiously?*

    There was some discussion about the CEC's CEQA and application review process as being complex and unfamiliar to most members of the public. A suggestion was made to consider a process similar to the manner in which local agencies adopt CEQA documents and review project applications. However, even with the CEC's process there has been involvement of interest groups and the public in the application review process.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

LAND USE RECOMMENDATIONS

1. Establish an early agency consultation process with local, regional, state and federal agencies potentially affected by proposed powerplant projects in order to identify land use and LORS issues prior to completion of the data adequacy process for AFCs. This process could also be used to identify alternative powerplant sites considered acceptable by the affected agencies.
2. Provide workshops or information sessions for affected land use agencies regarding how the Energy Commission's powerplant permitting process works and how the agencies can provide input.
3. Offer assistance to local and regional agencies in the development of programs that identify power needs on a regional basis (e.g., Sacramento Metropolitan area) as well as land areas appropriate for siting powerplants and related linear facilities.
4. Encourage local land use agencies to consider power needs of the community in their land use and planning activities (e.g., general plan and specific plan development processes and associated zoning ordinances).
5. Review local agency and public participation reimbursement regulations and/or develop guidelines to facilitate participation in the siting process.
6. Direct the Energy Commission staff to initiate early public agency coordination for powerplant licensing projects.
7. Consider re-structuring Energy Commission meetings and workshops to provide for easy input and comment from the public and affected public agencies.
8. Provide financial incentives or assistance to local agencies and/or applicants to assist in extending infrastructure to desirable powerplant sites.

LOCAL AGENCY AND PUBLIC PARTICIPATION RECOMMENDATIONS

1. The Energy Commission should direct its staff to conduct early meetings with local agencies to identify issues of concern to the agencies and the public.

2. The Energy Commission should direct its staff to request assistance from local agencies in notifying the public of the project.

3. The Energy Commission should direct its staff to work with local agencies in the preparation of analysis of the project, and where appropriate, use existing local agency documents or analysis to support the staff's assessments of the project.

4. The Energy Commission should consider whether a process similar to the California Environmental Quality Act environmental impact report or a process

similar to that used by local agencies to issue a conditional use permit would be appropriate. The Energy Commission should consider whether the trial-like features of the existing siting process could be reduced to facilitate public participation.

5. Evaluate local agency and public participation reimbursement regulations and/or guidelines to facilitate participation in the siting process.

TRANSMISSION CONSTRAINTS ON GENERATION SITING WORKSHOP SUMMARY

INTRODUCTION

On March 15, 2001, the California Energy Commission (Energy Commission) conducted the Transmission Line Issues Workshop to discuss requirements for conducting transmission line interconnection studies and transmission line constraints that may affect the licensing of future powerplants by the Energy Commission. A volunteer panel, comprised of transmission industry representatives discussed transmission line issues associated with powerplant licensing, information needed to develop appropriate actions to address constraints, and methods to avoid or lessen transmission line congestion related to the licensing of future powerplants.

OVERVIEW OF ORAL PRESENTATION

Mr. Jim McCluskey, representing the Energy Commission staff, provided a brief overview of the staff's workshop paper. The paper addressed two areas where transmission issues potentially could affect generation siting. One area is the Participating Transmission Owner (PTO) and California Independent System Operator – (CAISO) interconnection process. The second is the effects transmission line congestion may have on facility siting, especially where it may limit market access opportunities for new generators.

The interconnection process involves a number of participants and procedures. The process begins when an applicant submits an interconnection request to the connecting PTO and to the CAISO. The PTO may perform two studies, a system impact study and a detailed facility study. The impact study is used to identify potential reliability problems that would occur in the transmission system when a new generator connects to the grid. If reliability problems are identified in the studies, the applicant may request that the PTO perform a detailed study to determine what measures should be implemented to mitigate those impacts and to identify their associated costs.

Reliability impacts may be caused when new generators connect to the grid and create system conditions that violate accepted reliability criteria. These would include thermal, stability and voltage criteria violations. Some reliability criteria violations may be mitigated through remedial action schemes (RAS), such as measures that would curtail generation output during emergency conditions. Others may require transmission line expansion or replacement, or addition of transformers, circuit breakers or other system components. Current policies require that the connecting generator pay the costs of the interconnection studies and the costs of mitigating reliability problems.

The second area concerns congestion-related issues that could affect siting of new generation facilities. Congestion refers to increased loading on transmission lines and equipment. But unlike reliability problems, the grid operator is able to dispatch generation to reduce congestion so that the system can still serve load without violating reliability standards. Increased congestion usually causes higher transmission delivery costs. The addition of new generation resources to the grid may create new or aggravate existing congestion problems, with multiple effects. At some point it becomes necessary to identify longer term, more costly solutions to congestion problems, such as transmission expansions. The issue of who should pay to mitigate congestion problems has been a long-standing and contentious issue. In the past the CAISO adopted the position that the market should pay for such expansions based on the costs of congestion versus the costs of grid expansion. Others believe that new generators that cause or increase congestion when they connect to the grid should pay. To date a market approach to encourage transmission expansions has not worked for a variety of reasons and the Federal Energy Regulatory Commission (FERC) has rejected the view that new generation should pay transmission expansion costs.

PANEL. 1: TRANSMISSION LINE INTERCONNECTION

Mr. Jeff Miller, CAISO

Mr. Jeff Miller explained the CAISO's role in reviewing and commenting on interconnection studies, as well as the queuing process for generators. He also provided a brief overview on the number of generating projects the CAISO is reviewing and how they're distributed, as well as an overview of some of the major transmission projects the CAISO is considering.

The CAISO process is governed by the CAISO Tariff that has been filed at FERC. It is also governed by the tariffs transmission owners have filed with FERC, as well as the transmission control agreements that provide the CAISO with certain rights in the transmission owner system. The CAISO has a four-step process that is identified in that tariff. The first step is the interconnection request. The second is the performance of a system impact study (SIS). The SIS, performed by the PTO, is done to determine the impact of interconnection on their system, and to determine whether upgrades will be required. The scope for this study is generally agreed upon among the CAISO, the PTOs and the generation developer, before it is started. The model used to perform many of these studies incorporates the major transmission and generation facilities located in the western interconnected grid, west of the Rocky Mountains. The parties' use their collective understanding of the system to determine how severe they expect the impacts to be, and what should be covered in the study. The third step is the detailed facility study (DFS), which is used to determine exactly what measures should be deployed to mitigate impacts caused by the new facility, along with their costs. The fourth step is to coordinate with the rest of the Western Systems Coordinating Council (WSCC), and the Regional Transmission Groups.

While the WSCC has the ability to object to what is being proposed, the WSCC process is designed to deal more with major changes to bulk transmission facilities, like the interconnections between the Northwest and California, than with generation interconnection impacts. The major work effort is directed at the system impact study and the facility study that are carried out by the transmission owners with CAISO review.

The CAISO's present philosophy is not to require the generation developer to mitigate impacts on the major portions of the interconnected system but to require the developer to construct facilities to allow it to interconnect with the system. The CAISO also requires them to perform upgrades if there is a defined reliability problem associated with a new generation project.

The CAISO has developed a process involving a number of different approvals depending on the type of project. The one used most often with the Energy Commission is called a preliminary approval. Preliminary approval means that the CAISO is satisfied that the generation project owner has identified all the major facilities that will be required to connect their project into the grid. There may still be some outstanding interconnection issues, however, the Energy Commission can use the preliminary approval as the basis to determine what, if any, major new transmission facilities will be required to connect the generation project to the grid, and thus, what environmental impacts may occur. The CAISO has developed the preliminary approval process mainly to facilitate the siting process. The CAISO has also developed a conditional approval. This covers cases where the CAISO is unsure that all the impacts have been addressed, but it does not have all the documentation that it may need on the project from the transmission owner. With the presumption that the necessary documentation can be provided within a certain period, the CAISO provides a conditional approval, with final approval required prior to complete interconnection.

Given the current shortage in electricity supplies, the CAISO has recognized that transmission owners are required to complete studies in a short time frame, in some cases, in seven days. Therefore, the CAISO has shortened its process to a few days. As soon as the CAISO receives a notification from the generation developer, it initiates internal review. Within 24 hours the CAISO's planning engineers start the analysis. The CAISO attempts to provide a recommendation, for smaller projects, within two days of receiving the study. Larger and more complex projects could take longer. Mr. Al McCuen, representing the Energy Commission staff, noted that interconnection studies have never held up the Energy Commission licensing process. He noted that although it's been very difficult, the CAISO has been able to complete its reviews in a timely manner. It is quite common that the Energy Commission staff see a preliminary approval in as short as three days.

MR. David Korinek, SDG&E

Mr. David Korinek focused his comments on study resources, study process, study timeframe and queuing. He noted that the human resources available to conduct studies are a very limited commodity. In the entire state, including the PTOs and the CAISO, and qualified consultants, the people that are capable of performing these types of studies are numbered in the few dozen.

Mr. Korinek presented data that identified the number of studies his organization has been requested to perform. In 1998 and 1999 they had one or two sites each year to study. In 2000 they had over 30 sites to study. Based on requests this year to date, it looks like they will again be requested to perform about 30 studies. Notwithstanding the Governor's directive to expedite the studies for simple cycle and combined cycle units in 2001 and 2002, the average time required to do this type of study is still on the order of one to three months.

Mr. Korinek suggested that an applicant apply as early as possible. The earlier applicants enter the queue the better position they will be in to have their studies expedited through the process. He also requested applicants to keep in mind that there are others in front of them in the queue. Applicants need to understand the number of other applicants and their competing business plans and timetables. He also noted that competing applicants need to be given the same care and thorough analysis for their requests that they would, themselves, like to have.

Another option is the consideration of joint studies between applicants. In those cases where there are more than one applicant project connecting at a location in the system, or similar locations in the system, and on a similar timeframe, there may be an opportunity for those applicants to participate in a joint system impact study. This process would require applicants to make more disclosure of their business plans than, in some cases they're willing to do currently. Mr. Korinek encouraged applicants, where possible, to consider working with the PTO to determine if there are other applications that can be studied as a joint study. He also encouraged merchants to try to expedite the design and engineering of the facilities before the studies are done. In addition to study resources being limited, engineering, design and construction resources are also very limited. Mr. Kroinek noted that SDG&E supports the centralized queuing process by the ISO.

James Leigh-Kendall, SMUD

Mr. James Leigh-Kendall first discussed the issue of transmission studies. He believes studies need to be done and that they can be completed in a timely manner. SMUD's process is similar to the ISO's process. SMUD believes that common rules and processes are required to meet the timelines for building and interconnecting a generation project. Mr. Leigh-Kendall also discussed the constraints and upgrades that are identified through the studies. His main concern was that any new rules for a new project interconnection should add to, not diminish, the capability of the existing system to serve load. He sees a relationship between congestion and reliability.

Mr. Leigh-Kendall noted that under the old rule, new connections were made after other parties made system reinforcements. Since it was not necessary for all entities to pay for system upgrades when interconnections were made, a fairness question arose. Some parties could interconnect without paying, because there was an existing margin of capacity on the system. He noted that it's unfair to have the last project that causes a reliability problem to pay for massive upgrades that may be required by its interconnection.

He also noted that remedial action schemes (RAS) have increasingly become an easy solution to grid problems caused by an interconnection. SMUD has concerns regarding the potential consequences of not properly operating or coordinating the use of RAS. He also noted that the recent increase in the use of RAS tends to effect the more efficient units since these tend to be the more recent facilities deploying RAS to mitigate criteria violations caused by their interconnection. SMUD believes that constraints should be solved by upgrades, either transmission or generation, located close to load, rather than curtailment of generation through complex protocols such as RAS. The basic premise here is that adequacy and reliability should be looked at together.

Mr. Leigh-Kendall provided two recommendations. First he pointed out that all policies and interconnection procedures should preserve capabilities to serve load growth; this approach would utilize transmission upgrades or generation located close to load to mitigate reliability problems rather than using RAS. SMUDs second recommendation was that new generators should share the costs of mitigating reliability problems caused by interconnection, rather than having the burden fall on a single entity. He recognizes that this is a complicated issue and does not have a solution at this time but believes it is an approach that should be studied.

Mr. Morteza Sabet, WAPA

Mr. Morteza Sabet provided a brief overview of Western Area Power Administration (Western or WAPA) and its transmission and marketing functions. Although Western is a wholesale utility with no load growth obligation, load growth has resulted in additional use of its transmission system, thereby depleting its capacity margins.

Western has participated in the Sacramento Transmission Planning Group that conducted much discussion about the RAS philosophy versus downstream transmission expansions. Mr. Sabet believes it is necessary to look at each project in that project's setting. Therefore, public policies need to be flexible enough to allow the best results for the public investment.

The majority of Mr. Sabet's remarks were directed at the system in and around the Sacramento area. He believes that the area transmission capacity is not adequate to import the amount of power needed in the area in the long run; this will and is resulting in short term mitigation strategies, i.e., voltage support and remedial action. He noted that the Sutter Power Plant was allowed to be interconnected, since the area was better off with it than without it, even if its output may be curtailed by RAS during some emergency conditions.

Mr. Sabet appealed for parties to look at the public good aspect of what is being done, and give the transmission owners the ability to do the things that are necessary to solve problems. He stated that he did not think that asking the generator-developer to pay for the downstream infrastructure is going to work.

Manho Yeung, PG&E

Mr. Manho Yeung first discussed Pacific Gas and Electric's (PG&E) past and present workload for conducting interconnection studies. Over the past 14 months PG&E has completed about 35 generation interconnection studies, with considerably more activity during the past few months. For projects ranging from 100 to 1000 megawatt, the time it takes to complete these analyses has averaged approximately 145 days. They are able to complete studies for projects under 100 megawatts within 50 days. He reported that system impact studies typically takes about 60 days with facility studies taking an additional 90 days. PG&E also provides an expedited study that basically combines both the SIS and DFS studies that takes roughly 90 to 120 days.

In addition to the above studies, PG&E has also provided study support for the CAISO's summer 2001 Request for Bids effort for signing up peaking generation to be available for the summer of 2001. These studies generally, take three to four weeks to complete. PG&E is also in the process of developing a framework to implement the Governor's executive order that requires some interconnection studies to be completed in seven days. PG&E is focusing its study efforts on a more localized area, rather than looking at the broader system for this work. This is done through the use of engineering judgment and the knowledge of local areas. Generation proposals for these types of projects typically are of a smaller size, 50 megawatt or less and generally do not require the same level of detailed analysis that is required for the larger projects. PG&E has completed about ten of these projects, averaging 21 days.

PUBLIC COMMENT

Mr. Jack Pigott, Calpine

Mr. Jack Pigott pointed out that negotiating an interconnection agreement involves more than performing an engineering study. Since it is really a business negotiation it is difficult to place a time line on it. To the extent that the cost allocations can be determined ahead of time, a lot of the issues are removed from the business negotiation and it becomes a much faster process. He also pointed out that queuing is a major issue that creates cost responsibility problems and the potential for litigation that can slow down the interconnection process.

Mr. Pigott indicated that Calpine does not believe that the individual generators should be responsible for the bulk of transmission upgrade costs; he realizes, however, that this has to be within reason. He noted that there are sites that just don't make sense from a transmission standpoint, but thinks that most generators try to pick sites that are close to load where it makes the most sense to locate.

PANEL 2: TRANSMISSION CONGESTION AND ACCESS TO MARKETS

Mr. Jeff Miller, CAISO

Mr. Jeff Miller began by noting that congestion is not all bad, and does have some positive aspects. For one thing, the CAISO tries to use congestion to signal generators to locate at sites where it would be most advantageous from the CAISO's perspective for grid management. Typically it wants new generators siting close to load, and it tries to use its congestion management process and transmission losses to indicate these locations. Locating close to load can reduce the costs of both transmission congestion and losses for generators; locating at sites remote from load centers can increase those costs. However, locating close to load raises air quality, water, and public opposition issues. Consequently, there are advantages and disadvantages siting projects near load centers as compared to remote locations. Mr. Miller stated that aside from reduced line losses and congestion there may not be a great advantage to generators to locate near load. While there are some incentives the CAISO can use to influence locational decisions for new generators, there is no automatic process.

The CAISO plans to submit a new generator interconnection policy and long term grid planning procedures to FERC in the near future; those procedures should provide some locational incentives for new generation. The new facilities interconnection process will include a policy regarding whether new generators will have to mitigate incremental congestion they cause. The proposed grid planning process will include a competitive solicitation process through which transmission proposals could be weighed against generation and load management alternatives that could accomplish the same objectives as transmission, but at lower costs and with fewer environmental impacts.

Mr. Miller stated that the CAISO would welcome an expanded planning role by the CEC. He also said that many generation applicants are proposing siting facilities in areas that are remote from load centers such as the California-Arizona boarder. He said the CAISO is thinking about developing a 500 kV transmission line to bring this generation from this area to load centers in California. He also said that the CAISO's congestion management procedures are not working well as they allow for gaming by market participants. The CAISO is currently working on a comprehensive market reform policy to address these problems. One of the elements of the policy is a revised congestion management procedure that will provide more effective congestion pricing signals to indicate optimal locations for siting new generation.

Mr. Eddie Lim, SMUD

Mr. Eddie Lim's presentation focused on two areas. First, he wanted to provide the Committee with an understanding of remedial action schemes (RAS) and their application and potential problems. Second, he discussed SMUD's concept of energy parks. Mr. Lim said that SMUD is concerned about the potential overuse of RAS. He said that RAS are similar in some ways to highway metering and control systems that try to control congestion and the flow of traffic. Both have manual and automatic mechanisms for controlling flow problems. Whereas traffic mechanisms control the flow of traffic, RAS are used to reduce power plant output to prevent transmission lines from over loading and causing reliability problems. SMUD believes that RAS have limited application as short-term measures to address potential reliability problems, however, they should not be used as substitutes for transmission expansions to mitigate those problems in the long term. The increased use of RAS SMUD is seeing is because of their relatively low costs, when compared to transmission expansion.

Mr. Lim then moved to a planning perspective. He noted that urban development requires planners to design and create zones for different types of development - residential, industrial, commercial, wetlands, etc., but that we don't plan areas for energy zones. He suggested that energy zones could be planned in a similar way to other areas. He envisioned energy zones as land tracts where certain necessary services for operating powerplants such as water, natural gas, electric transmission facilities and sewer systems are in place and potentially ready for use by power plant developers. The Rancho Seco Site is an example of a potential energy park. It is close to a load center, has available water, transmission, zoning for power plant development, and room for about 2000 mw of generation. However, it lacks gas facilities. Mr. Lim knows there are many transmission studies underway now and that as part of this study process potential energy zones could be identified where we could add generation and minimize the need for transmission additions and the use of remedial action schemes.

Mr. Morteza Sabet, WAPA

Mr. Morteza Sabet began by saying that he has been pleasantly surprised that power plant developers are doing a good job of identifying good sites to locate their facilities.

They are looking for sites with water, sewer, and gas and also conducting power flow analysis to identify the best sites to locate.

Mr. Sabet next said that he is fairly comfortable with the use of RAS schemes, at least as they have been applied in the Sacramento area. He believes the area is better off with the use of RAS (at the Sutter power plant location) than without it; and though a transmission expansion would have been a better solution for dealing with the problem, no one would finance and build it. He does not believe RAS schemes are sustainable over the long term in the Sacramento area, however, because the transmission system is reaching its limit. He believes there are overall problems with the use of RAS as they depend, to some extent, on human decisions and different operators may have different opinions as to how to address problems; this is why there are automatic backup systems. He said that in a rural area, at the end of a transmission line, RAS applications may be quite acceptable because they may not have impacts on the system if generation is curtailed.

Regarding transmission planning to bring power to the Sacramento area, Mr. Sabet said that WAPA is conducting initial transmission planning studies and examining several corridors in which to build 230-500 kV transmission lines to bring power to the area in case new generation isn't sited locally. He said there is uncertainty associated with building additional transmission as planners don’t know where or if new generation is going be developed in the region. One reason for this is there are survival problems with applicants seeking to site new generation in the state. He said that if generation is planned then WAPA can build transmission to that point, but planning transmission in cases of uncertainty is difficult. There are also problems with transmission planning in the state, especially with the CAISO/PTO planning process. He said that when planning new transmission facilities WAPA is able to identify corridors, obtain financing, and conduct environmental studies in advance. With the CAISO/PTO grid planning process, however, no one is responsible for initiating economic projects to eliminate congestion or provide market access and guide these projects through the planning and developmental stages, except on a voluntary basis. He believes that market forces are not working in these situations to stimulate investment in economic transmission expansions.

Ms. Nancy Werdel, WAPA.

Ms Nancy Werdel discussed issues concerning voltage support in the Sacramento area and environmental constraints associated with building transmission lines. WAPA started an environmental impact statement (EIS) for voltage support projects in the Sacramento area a year ago. Enhanced voltage support could be accomplished via several types of alternatives including transmission upgrades, new transmission lines, local generation, and demand side management. The EIS will be used for evaluating both short-term (next 5 years) and long-term solutions. It will also provide the foundation for longer-term projects such as a potential 500k-kV line into the area. The federal EIS is approximately a 2 year study. Mr. Sabet pointed out that they had examined both 230 kV and 500 kV lines for local area voltage support. The problem with 230 kV lines is that by the time they are completed the area will need additional transmission. He said that they haven't yet obtained project sponsorship or funding to build the lines but they know where the feasible corridors are and they have a general buy-in from customers and generators. Mr. Lim from SMUD said they have also been studying the voltage problem in the area for the past two years and would like to consider locating generation close to load at a Rancho Seco "energy park" as a possible solution to the problem. This might make the area an electricity exporter, rather than continuing to rely on imports. He suggests this could be an alternative to running 500 kV lines to the area. He would like to consider bringing this before the Commission as an option. Mr. Sabet agreed with this proposal.

Ms. Werdel spoke next about environmental constraints to building transmission lines. One problem is that it is difficult to significantly expand transmission right of ways or find new ones. Public opposition to new lines is increasing and the longer we wait the more constraints will develop. Commissioner Laurie asked about the extent to which upgrades can be made within existing rights of way. Mr. Sabet said that in the past utilities used to conduct long term transmission planning and buy rights of way in anticipation of future need; this has greatly diminished. Ms Werdel said that urban sprawl is limiting where new transmission lines can be located or existing capacity upgraded. Mr. Yeung said that PG&E does not have adequate transmission rights of way for system expansions over the next 20-25 years. Also, in the past utility land acquisition often occurred in bits and pieces. Commissioner Pernell asked if anyone is doing, or has done 20 year planning. Mr. Sabet said a comprehensive study was done in the mid 1990s and he will provide a citation. Ms.Werdel said that WSCC's environmental work group may be doing this kind of planning. Mr. Miller thinks there is a gap in grid planning at this time. Deregulation shorted the planning horizon from 10 years to 5 years, which has created problems because it takes as long as 6 years to permit some transmission projects. He said the CAISO plans to use a 10 year planning horizon. No one, however, is in the lead attempting to identify transmission corridors.

Mr. Jim Philippe, PG&E Corp

Mr. Jim Philippe discussed both interconnection and congestion issues and solutions during his presentation. He said that interconnection disputes between PTO's and developers are barriers to new generation siting. Currently, interconnection policies differ from PTO to PTO and developers must accommodate those differences. Differences occur now because each PTO has a different interpretation of the tariffs. A solution to this problem is for the CAISO to adopt a single, uniform interconnection policy that applies to all PTO's. It would also be helpful if the CAISO resolved interconnection disputes between PTO's and applicants. Currently the applicant and PTO try to resolve disputes between themselves. They can also go to FERC for resolution but that can be a long process.

Mr. Philippe said that new generators should be responsible for correcting reliability problems they cause when they connect to the grid, but not for mitigating congestion problems. The CAISO should also be responsible for determining what upgrades are necessary for a reliable connection and it should stop there. It slows powerplant licensing if reliability issues are addressed during the interconnection study phase of the process and then litigated again as part of the Energy Commission's siting process. This occurs when intervenors use the Energy Commission process to challenge study results and introduce claims. Apparently, the Energy Commission staff does not perform additional technical studies of the interconnection after the CAISO/PTO interconnection studies are completed. Mr. Phillippe thinks that 60 days to do a system study and 60 days for a DFS would be good, but sometimes the studies take longer.

He said that queuing procedures for interconnection studies and the Energy Commission siting process need clear milestones; and project developers should be required to meet those milestones or lose their place in the queue. Cost allocation is also an issue. Urban planning approaches may require developers first into an area to pay the costs of expanding the highway and off ramps to accommodate later development and be reimbursed by additional developers on a prorate basis. There is no similar provision for generation developers trying to interconnect within the same area to share reliability mitigation costs caused from their interconnection. PTO's require developers to mitigate the impacts of their own interconnecting facilities.

Regarding congestion issues, Mr. Philippe said that new and existing generators in California compete for transmission capacity and this is good as it encourages economic efficiency, but it can also keep existing generators from the market. Congestion, if unabated, can also add significant costs to electricity and to ratepayers and it can narrow supply margins and add to reliability problems.

Remedial action schemes are useful if they have limited application, but shouldn't be used as alternatives to transmission expansions. It would be better if the CAISO and PTO's develop a proactive approach toward congestion mitigation and transmission expansion. He also thinks that the CAISO and PTO's should conduct an assessment of uneconomic congestion and if it is identified, they should plan and build transmission expansions for congestion relief. He believes the market has been ineffective in stimulating these kinds of projects and that trying to have the market finance transmission projects is a "prescription for failure." It would be better to have the CAISO plan and build these projects with ratepayer financing.

Because it is important that developers know where grid congestion exists and the capability to connect generation to the grid, Mr Philippe said that a state role could be to provide information to developers about congested areas in the state. Developers, the CAISO, and the regulatory community need to look at this question more proactively, if new generators are to locate close to load and not simply try to site generation at the cheapest, easiest location.

PUPLIC COMMENT

Mr. Pigott, Calpine

Commissioner Laurie began by asking Mr. Pigott whether he considered transmission a barrier to Calpine's generation development plans? Commissioner Laurie also asked whether, from Calpine's perspective, there is coordination work the state can do to benefit generators? Mr. Pigott said that transmission constraints can be both opportunities and barriers. It is almost always better to locate generation inside congestion zones, especially as the CAISO creates more and smaller new zones. Locating within zones will provide more opportunities to operate and perhaps higher prices. Exporting power outside a zone will cost more. To open competition, however, it is important to have more transmission capacity to get the power to the market. As far as a state role in this area, he suggested that the state could be proactive in relieving constraints on transmission lines, although he did not provide any specific recommendations.

Mr. Shishir Mukherjee

Mr. Shishir Mukherjee discussed two issues: state ownership of the transmission grid and transmission tariffs. He stated that he believed that when California deregulated, the state should have taken over the transmission system. He does not believe the present system is working. He said that even under regulation utilities did not provide adequate transmission in some areas, siting the example of the San Francisco Bay Area. In addition, the state's transmission system was planned by the three major Investor Owned Utilities (IOUs) to serve their needs, not as a state system. It is now operated by the CAISO as a single system and this leads him to believe that deregulation has changed the way power flows on the grid. Second, Mr. Mukherjee said that the current transmission tariff is a postage stamp tariff and sets a single price for transmission service regardless of the distance power is transmitted. This leads to inefficient use of the grid.

Mr. Mark Smith, Florida Power and Light

Mr. Mark Smith said that Florida Power and Light (FPL) is currently attempting to license a project in the Rio Linda area. Mr. Smith was concerned that the Committee expressed a distrust of the market as a means to bring new generation on line. Commissioner Laurie assured him that he trusts the market to bring forth generation proposals. Commissioner Laurie said that he does not trust the market, from a long term planning perspective, to locate new generation where it should be located from the state’s perspective since each generator will serve only its particular needs not the state’s. Mr. Smith agreed that the generation community is a bit myopic in this regard.

Mr. John Fistoraro, NCPA.

Mr. John Fistoraro explained that the Northern California Power Agency (NCPA) was a joint powers agency of northern California municipal utilities. He said that NCPA has endorsed the concept of a not-for-profit transmission company and that the state could serve in this capacity, but that there are other alternatives. Examples would be NCPA and or the Transmission Agency of Northern California (TANC). TANC has recently proposed to upgrade Path 15 in cooperation with WAPA or the State, to reduce congestion problems between southern and northern California. Mr. Fistoraro said that congestion on Path 15 is a major concern for California and for the Western Region. In response to a question on time of completion of a Path 15 upgrade from Mr. Pernell, he stated that TANC already has environmental work underway for an upgrade and that he thought that with state cooperation a best case could be the end of 2002. Mr. Sabet said that this was optimistic as WAPA estimated three years to perform this work from the time the money was deposited. Mr. Fistoraro noted that there is broad support for the project at the federal level and by the state, but the federal government needs state commitment before it provides financial support.

Mr. Paul Scheuerman, Alpine Consulting.

Mr. Paul Scheuerman expressed concern with the use of RAS for other than "infrequent contingencies"; they are being used for situations for which they are not intended, as a low cost substitute for transmission expansions. For example, he thinks RAS is being used to curtail generation during peak load periods to prevent transmission line overloads, but this reduces the amount of generation available to meet peak load conditions. The proper solution would have been to expand the transmission system to allow generation to meet peak conditions, but this is the more costly solution. RAS may serve as a temporary fix, but at some point it is necessary to improve the transmission system. Mr. Sabet agrees that they are temporary solutions in most cases, and that over the longer term it is necessary to improve the transmission infrastructure.

ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 1: Are requirements to conduct transmission line interconnection studies delaying certification of new projects?

1. *Interconnecting generators are responsible for the costs of mitigating reliability problems caused when they connect their facilities to the existing transmission system, including responsibility for reliability problems that are created downstream of the point of interconnection. Disputes between the connecting Participating Transmission Owner (PTO) and applicant sometimes occur over the extent and costs of reliability problems caused by the applicant generator. This occasionally has created uncertainty for developers regarding interconnection costs and can affect AFC timelines when downstream facilities may be required.*

   One party said disputes between applicants and generators sometimes occurred and that there is no formal procedures for resolving such disputes, except through FERC. He suggested that the CAISO should develop a dispute resolution process to help expedite the process. No data was presented during the workshop to indicate any appreciable impacts on the interconnection process associated with these situations. No process changes are recommended; however, also see the discussion of queuing impacts below.

   On a related issue, several parties urged that the costs of mitigating reliability problems should be shared among facilities connecting at the same location on the grid and contributing to the reliability problem. Current PTO policy is for each party to pay the costs of mitigating the problems it causes.

2. *The California Independent System Operator (CAISO) and PTO interconnection process has typically required 60 days or more from the time a Detailed Facility Study (DFS) or System Impact Study (SIS) is requested until it is provided to the applicant and CAISO. In addition, the CAISO typically takes 14 to 30 days to review and approve a DFS or SIS and return it to the PTO for revision. Do the timelines for PTO interconnection studies and CAISO review of those studies create a barrier to timely completion of the Energy Commission process?[1] What other situations tend to delay the interconnection process? What remedies are needed to solve those problems?*

[1] The CEC CAISO Memorandum of Understanding specifies 120 days for whole process.

As noted by Mr. Al McCuen during the workshop, to date the CAISO study review process has not impeded the Energy Commission staff's review process. Additionally, the PTO's are implementing accelerated schedules for smaller power plants where applicable. The overall transmission interconnection study process, as carried out by the PTO's and CAISO, does not tend to add time to the overall approval process, since it is carried out in parallel with other permitting and review processes.

It should be noted that on April 2 the CAISO filed a new facilities interconnection process. This new process formalizes the ISO's central role in coordinating the interconnection studies, leaving the actual study work with individual PTO. Timelines remain much the same as outlined during the workshop.

3. *Queues are utilized by each PTO and Non-Participating Transmission Owner (NPTO) to model the generation units that are assumed to be on line in order to determine reliability criteria violations in interconnection studies. Placement of a generator in the queue at the time of these studies can affect whether or not a developer's project would cause reliability violations, thus potentially increasing a facility's costs of connecting to the grid. The PTOs and NPTOs also have different methodologies for establishing queues and the queue is usually confidential information. Do these factors create uncertainty for developers concerning the costs of connecting to the grid? Do PTO, CAISO or NPTO queuing procedures create impediments to timely facility siting?*

   The position in the queue can influence the costs that a developer may be required to pay, and therefore, does introduce some uncertainty into the process. However, the uncertainty introduced has more to do with the question of weather or not the developer's place in the queue is representative of his project's actual construction schedule relative to other projects. Given the confidential nature of project schedules and related data, it will be difficult to remove the uncertainty.

   Since each PTO maintains its own queue, it is possible that the assumed development timeline for various projects could be different from one PTO to the next. One feature in the recent CAISO filing noted above provides for the CAISO to maintain one central queue. The maintenance of the one queue should help reduce questions and uncertainty.

4. *The siting jurisdiction of the Energy Commission and California Public Utilities Commission (CPUC) overlap for some projects where new generation would cause downstream reliability problems and new facilities would be required to mitigate reliability criteria violations. Does this create delays or other impediments to siting new generation facilities? Would a single regulatory agency, responsible for licensing both generation and transmission, mitigate such impediments (if they exist)? Would having a single regulatory authority, responsible for licensing both generation and transmission, make it easier to determine whether new generation or new transmission is preferable to meet local needs*

To date no information has been offered to suggest that joint siting authority between the Energy Commission and CPUC causes delays or other impediments to the siting process.

Currently the CAISO determines the extent, if any, to which a non-wires project will be perused as an alternative to a transmission project. They carry this process out as part of their overall market development and reliability process. It would seem that the preferred means of meeting load should continue to reside with the ISO, if for no other reason than, for reliability purposes. Since the CAISO does not have “regulatory” or “licensing” authority there remains a need for a second agency to exercise the regulatory and licensing provisions of the law. Additionally, since the CPUC bears the responsibility for setting rates for retail transmission, it seems appropriate that they have input into the approval of new transmission facilities through the CPCN process.

Issue 2: What siting constraints are the result of transmission congestion and access to markets? How should those constraints be resolved?

1. *Does transmission congestion in some locations limit the ability of power plant developers to access electricity markets, and does this affect their siting decisions? What factors are most responsible for influencing such decisions?*

   Congestion does influence siting decisions by new generators. The CAISO prefers to have generation locate close to load centers and uses transmission congestion to signal it's preferences in siting locations. Locating close to load reduces congestion costs and losses for generators, but it may raise air quality, water, land use, and public opposition issues, that also have costs associated with their resolution. Locating remote from load increases the costs of congestion and losses. It may also require expensive transmission additions to obtain market access. Locating new power plants is a balancing act of whether to locate close to load and address environmental and land use issues or locate in more remote areas and solve congestion and grid expansion problems.

   If transmission capacity is available, congestion and grid expansion costs may not be significant barriers to locating generation remote from load centers. However, the availability of transmission to remote areas may be a problem. Transmission planners said they are often uncertain where generators will locate and it is difficult for them to plan transmission to serve new facilities under conditions of uncertainty. The CAISO also has transmission planning issues, as it has not been proactive in planning and developing economic transmission projects. The CAISO does plan a more proactive role for itself in the development of economic transmission projects.

   SMUD proposed energy parks as potential sites to locate generation. Energy parks are relatively large land tracts capable of accommodating significant generation capacity. They would be suitable from environmental and land use perspectives and would have transmission, gas, and water facilities available. Rancho Seco is a potential park site. They could also provide transmission planners with a much higher level of certainty for planning transmission facilities to service new generators.

2. *Does increasing congestion caused by new generators connecting to the grid limit the ability of "in place" generation to compete with newer power plants for transmission access? Does this adversely affect the ability of existing generation to get their power to market? If transmission access for older generation is limited by this circumstance, would this eventually affect the amount of net generation available under some conditions*?

   Only one panelist commented on this issue. Mr. Philippe said that new and existing generation competes for transmission access in congested areas and it can keep existing generators from the market. Unabated congestion can add significantly to the costs of electricity for rate payers and can narrow supply margins. He suggests a more active role for the CAISO in planning transmission to relieve congestion problems.

3. *Congestion problems can result when transmission lines become overloaded under heavy use and system dispatchers must dispatch around constraints or take other remedial actions to avoid reliability problems and still serve load. Should these "remedial action schemes" be viewed as short-term or long-term solutions to congestion?*

   Panelists believe there is a trend toward increased use of remedial actions schemes (RAS) to address reliability problems, because they are relatively inexpensive fixes for solving certain reliability problems. It was also mentioned that RAS may provide benefits under some circumstances (Calpine's Sutter generation project is an example). All panelists expressed concern with the widespread use of RAS over the long-term as a substitute for transmission expansions. The use of RAS causes several problems. It does not add transmission capacity to the system, and thus, does not reduce system congestion or provide increased market access. Coordination problems among control areas are also a concern. Finally, if RAS is used only under certain extreme conditions, e.g., peak load emergency conditions, it may reduce generation output from a facility when it is most needed by the system under peak load conditions.

4. *The CAISO does not require new generators to mitigate congestion problems they cause when they connect to the grid, as it does reliability problems; rather, it assumes that such problems will be solved through market forces. This approach has not worked as anticipated. In addition, the CAISO's grid planning process focuses on resolving reliability problems, not congestion problems. The result seems to be a flaw in the CAISO's grid planning procedures. What alternatives to the present approach to planning and financing transmission expansions to address congestion issues would be most effective in resolving this problem? For example would state involvement and funding, CAISO and PTO planning and financing, or redesigned market mechanisms be more effective?*

Panelists offered various levels of support for the three options proposed in the OII Notice. We also briefly summarize a land use model for transmission expansion suggested by Commissioner Laurie.

Market Option. Virtually no one suggested that a market approach for resolving congestion problems should be further explored. It was argued that it is difficult to encourage investment in market based projects because there are insufficient incentives and potential benefits are too widely dispersed among different parties. This discourages cooperative efforts to jointly finance such projects. The more general problem is that no single entity or group of entities that participates in the CAISO planning process, is responsible for planning, financing and building economic transmission projects.

CAISO/PTO option. Most parties did support a more proactive role for the CAISO and PTOs in planning and developing transmission facilities to relieve congestion and provide market access. Mr. Miller said that the CAISO is proposing a more proactive role for itself in this area in its long-term grid planning process. PG&E and WAPA representatives also expressed support for a more proactive role for the CAISO in this area.

A State Role. There was support for an enhanced state role in the transmission planning area. One party suggested a role for the state in identifying transmission constrained areas and providing that information to developers to expedite the interconnection study process. It was also suggested that the state investigate potential transmission rights of way to secure long-term transmission planning opportunities. Several parties recommended state ownership of the CAISO-controlled transmission system.

A Land Use Model. Commissioner Laurie suggested a model for grid expansion based on a land use planning approach. The model requires developers and builders to pay for highway expansions and off ramps to reduce road congestion caused by their developments. By analogy, generation developers would be required to mitigate incremental congestion caused by their facilities and to allocate pro-rata costs to future developers. There is currently no provision for this in the interconnection process as the PTOs require each developer to mitigate its own reliability problems. The model may not be applicable because FERC has rejected the concept that developers should pay to relieve incremental congestion (as opposed to reliability problems) they cause as a result of interconnection.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

- The Energy Commission should support efforts by the CAISO and PTOs to plan, finance and develop economic transmission projects to reduce congestion and provide market access.
- The Energy Commission should direct the staff to obtain information concerning trends in the use of RAS on the state's transmission system, the consequences of

a proliferation of RAS, and the consequences on facility siting in the state if the use of RAS is limited as a tool for mitigating reliability problems.

- The Energy Commission should direct the staff, in coordination with the CAISO and PTOs, to explore potential locations for, and the costs and benefits of, energy parks as siting locations for new generation facilities.
- The Energy Commission should direct the staff to examine whether it is feasible for the Energy Commission to undertake a role in identifying potential transmission rights of way, in order to secure future corridors for long term grid planning.
- The Energy Commission should direct the staff to examine the feasibility of an Energy Commission role in developing information on transmission congested locations in the state and use this information to inform siting applicants of advantageous siting locations.
- The Energy Commission should recommend to the CAISO and PTOs to jointly explore the feasibility and benefits of generators connecting at a common location on the grid, to share the costs of mitigating reliability problems caused by their interconnections.

TIMING OF FEDERAL PERMITS WORKSHOP SUMMARY

INTRODUCTION

On March 27, 2001, the California Energy Commission (Energy Commission) conducted the Timing of Federal Permits Workshop to discuss federal permit timing issues that may affect the licensing of future power plants by the Energy Commission, to identify those processes that are working well, and to provide recommendations on potential improvements that may be made to address these issues. The workshop was composed of two separate volunteer panels that addressed issues affecting regulatory approvals and interconnection and land use approvals.

OVERVIEW OF ORAL PRESENTATIONS

STAFF PRESENTATION

Mr. Chris Tooker, the Energy Commission's Siting Policy Program Manager, provided an introductory statement, explaining that a revised March 21, 2001 Staff Issue Paper had been to better describe the progress already made in addressing federal coordination issues and better focus the workshop discussions.

Mr. Gary Meunier, representing Aspen Environmental Group (staff's consultant), then summarized the Staff Issue Paper. Mr. Meunier explained that the Issue Paper first looked at the broad variety of Federal permits and agency approvals involved in siting a power plant. Then it focused on several of permit processes that have the potential to constrain the Energy Commission's siting process. These included

- Permit processes under the Endangered Species Act,
- Prevention of Significant Deterioration (PSD) permits under the Clean Air Act,
- National Pollutant Discharge Elimination System (NPDES) permits,
- Federal land use entitlements (e.g., rights-of-way and special use permits) for pipelines and transmission lines or other facilities, and
- Permitting requirements related to Indian Reservations, tribal treaty rights, and Native American concerns.

Mr. Meunier also explained that the paper identified some key issues including: application completeness; delays in review of application materials; development of mitigation measures; agency workload and staffing; coordination and scheduling issues; changes in law or regulation; processes for appeal of agency decisions (e.g., to the U.S. Environmental Protection Agency's (USEPA) Environmental Appeals Board (EAB)); and potential delays in the permitting of pipelines and transmission lines that would need to be developed in conjunction with power plants. In response to a question from Commissioner Laurie, Mr. Meunier confirmed that there are no power plant-specific permit processes at the Federal level, as there are in California.

Mr. Tooker then introduced the USEPA panelists, expressing his appreciation for the USEPA's cooperative and timely participation in the Energy Commission's power plant licensing process.

PANEL 1: REGULATORY APPROVALS

Steven Barhite and Ann Lyons U.S. Environmental Protection Agency Region IX

Ms. Ann Lyons started by providing an overview of the federal permitting process under the Clean Air Act. First, air districts in California issue permits under the State Implementation Plan (SIP), which is mandated by federal law. Such permits are still Federal permits, subject to review by the USEPA. There are also Federally permits, such as Prevention Of Significant Deterioration (PSD) permits, that are issued by the USEPA in some cases, and in other cases by PSD delegated districts.

In response to questions from Commissioner Laurie, she explained that when the USEPA approves a district's portion of the SIP, part of its review is to determine whether a district has adequate legal authority and funding to implement the permit programs required under the Federal Clean Air Act. She also explained that, if a district issues a permit that the USEPA does not approve of, remedies could include taking a direct enforcement action against the source or a procedure where the USEPA can withdraw the permitting program from the state and take over the permitting. She added that this action has never been taken before. She emphasized that it's very important to make the applicants aware of the fact that the USEPA has the oversight and enforcement role for the Federal Clean Air Act. She said that applicants should be encouraged to submit complete applications with respect to Federal requirements.

Ms. Lyons then described the regulatory processes for non-attainment and attainment pollutants. Federal air quality standards have been adopted for ozone, nitrogen oxides, particulate matter, carbon monoxide, sulfur oxides, and lead. Non-attainment pollutants are those for which air quality standards are being violated. Air districts are required to develop and implement a permit program to reach attainment for these pollutants. This permit program is incorporated into the SIP.

PSD requirements apply to attainment pollutants. In many instances, USEPA administers the PSD program. However, some districts have developed their own regulations to implement the PSD requirements and have be delegated PSD authority by USEPA. A district that is delegated PSD authority may have its own administrative remedies to address appeals of PSD permits. However, USEPA's Environmental Appeals Board retains authority to review PSD permits.

Mr. Steven Barhite indicated PSD authority is complicated in California because 34 districts are involved, some have delegated PSD authority and some do not. In response to a question from Commissioner Laurie, he indicated that the California Air Resources Board (ARB) has done a good job of coordinating the processes of these 34 districts. Ms. Lyons added that a further complicating factor is that the programs of the districts have evolved historically to address different kinds of local sources.

Ms. Lyons discussed the need for compliance with Section 7 of the Endangered Species Act and the potential for appeals to the EAB for the federal permits (including those by delegated agencies). She also stressed that the term “mitigation” is not used in air permitting, but that the appropriate term “requirements”. Federal regulations address emission control technology requirements and specific requirements for emission offsets for non-attainment pollutants.

Mr. Barhite stated that emission control technologies and emission limits have been an issue in a number of the earlier powerplant cases. However, since ARB issued its report “Best Available Control Technology Guidelines for Powerplants”, issues regarding emission controls have been less controversial. Consequently, the main focus has been directed to offsets. Applicants need to work on obtaining offsets early on, looking for sources that can be over-controlled. Mr. Barhite cited the creative use of mobile source offsets for the Otay Mesa project, where the applicant worked with the district, ARB, Energy Commission staff, and USEPA to develop these emission offsets. The key in San Diego was the short attainment horizon, as opposed to the long attainment horizon for the South Coast Air Basin. This makes the short-lifespan offsets, such as mobile offsets, more problematic in South Coast.

Ms. Lyons then explained that on June 30, 2000, the EAB issued procedures for dealing with frivolous appeals on an expedited basis. Commissioner Laurie asked how environmental justice may be addressed by the EAB. Ms. Lyons responded that if environmental justice is addressed during the permit process, the EAB could dismiss an appeal based on environmental justice issues. If not, substantive demographic issues may need to be addressed in the appeals process. In reply to Commissioner Pernell, Ms. Lyons stated that the above-referenced procedures are specific to PSD permits.

Mr. Tooker asked about overlaps and consolidation of the NSR and the PSD programs. Mr. Barhite explained that analyses for the PSD permit often rely on those conducted for the districts NSR program. If the district’s NSR analysis is good, then the PSD permit will often follow very quickly thereafter.

Ms. Susan P. Jones, Biologist, USFWS

Ms. Susan P. Jones explained that she has worked on endangered species issues on several power plant projects recently permitted in Kern County. She explained that the mission of her agency is to recover species greatly reduced in numbers primarily due to habitat loss. The U.S. Fish and Wildlife Service (USFWS) has written recovery plans to protect habitat for many of the species listed as threatened or endangered (i.e., listed species). In addition, USFWS has two approval or permitting processes under Sections 7 and 10 of the Endangered Species Act (ESA). Section 7 applies when another federal agency must take an action on a project. Under Section 7 the federal agency must consult with USFWS or the National Marine Fisheries Service (NMFS), if a project could adversely affect a listed species or designated habitat (i.e., a federal nexus exists). Section 10 applies when there is no federal nexus. The USFWS’s objective is for no reduction of listed species below current baseline levels, which may require mitigation to achieve this goal.

The Section 7 consultant process has a regulatory deadline of 135 days (30 days to review information provide for completeness, and then 105 days to issue the Biological Opinion). In response to questions from Commissioner Laurie, Ms. Jones confirmed that sometimes field surveys done at certain times of the year are required to provide the information needed to complete the analysis for a Biological Opinion. That is why projects proposed at previously developed or greatly disturbed sites can go through more quickly (e.g., the Elk Hills project that was proposed in a disturbed area). Regarding emergency siting, Ms. Jones indicated that the process can take less than 135 days, but that due to staffing limitations they have not been making the 135-day schedule on unexpedited projects.

Commissioner Laurie asked about the Procter & Gamble project where fairy shrimp were discovered in some tire track indentations, which caused the process to go beyond 135 days. Commissioner Laurie asked if the process has been changed to address power plants at industrial sites. Ms Jones said that pre-approved mitigation (conservation banks) for fairy shrimp has been set up. In addressing a follow-up question by Commissioner Pernell, Ms Jones stressed that the emergency sites being identified by the Energy Commission are industrial sites that have already been surveyed, so permitting could be done quickly without impacting endangered species.

Ms. Jones discussed the California Department of Fish and Game’s (CDFG) database for endangered species, and the need for its update and for the staff to maintain this database. Commissioner Laurie then inquired about other studies needed in addition to examination of the CDFG database, for undisturbed sites. Ms. Jones replied that applicants usually have to conduct site studies to determine the existence of listed species. She also said that the USFWS has habitat information that can be provided to the applicant that identifies those species that could likely occur at the site or in the vicinity. The applicant could survey for these species or just assume that they are present, and agree to apply mitigation (e.g., buy acres in a conservation bank).

Ms Jones explained that a Section 10 permit, which is applicable to when a federal nexus is not present, has no mandated deadlines. Therefore it can take much longer than a Section 7 consultation. She recommended that applicants find a federal nexus (some federal jurisdiction) to speed up their project. Under Section 10, the USFWS is writing Habitat Conservation Plans (HCPs), primarily focusing on county-wide plans. USFWS has few staff for this work, and therefore, individual projects have a low priority.

Commissioner Pernell asked about appeals, and Ms. Jones stated that there is no appeals process; the USFWS tries to work out problems with the applicant. The applicant can go up the chain of command in the agency or to court to get a decision changed. Ms. Lyons mentioned that there is the Federal Administrative Procedure Act, which provides for judicial review of agency decisions to determine if they are arbitrary and capricious. Mr. Mulvey and Ms. Lyons also indicated that under the Section 7 consultation provisions, if the endangered species protection provisions were incorporated in the Federal permit that triggered the Section 7 (e.g., a PSD permit), then those permit conditions may be appealable through the applicable appeals process.

Ms. Jones closed by indicating that the USFWS has been working well with the Energy Commission staff. It would helpful if the applicants came to the USFWS earlier in the process before the project location and components are set, and if applicants selected sites that do not have listed species issues. She mentioned reluctance by applicants to do timely surveys, and the staffing shortage at the USFWS. She also suggested early involvement of the USFWS during pre-filing meetings with the applicants and suggested monthly coordination meetings, such as those conducted between the USFWS and the U.S. Army Corps of Engineers. She asked for more information on upcoming transmission projects. She suggested that the CDFG needs staffing to update the Natural Diversity Database. She recommended the establishment of conservation banks, and suggested using PG&E and SCE lands with habitat value. In response to Commissioner Laurie, it was stated that such mitigation is not necessarily site-specific, but is species-specific.

Mr. Brian Mulvey, National Marine Fisheries Service

Mr. Brian Mulvey described a handout that he provided that outlined the role of the National Marine Fisheries Service (NMFS) and their legal and regulatory authorities for protecting species and habitats (e.g., under the ESA and the Magnuson-Stevens Fishery Conservation and Management Act). In California, ten listed species (of salmon and steelhead) fall under the NMFS jurisdiction. The NMFS is involved when power projects affect aquatic habitats. NMFS's review can be required almost anywhere in California, since these species can be found in coast waters, inland waters and estuaries.

Commissioner Laurie asked about the difficulty of permitting hydroelectric projects. Mr. Mulvey stated that where listed species are present, mitigation would be very difficult. Mr. Tooker asked about the site locations or kinds of impacts that could trigger NMFS involvement. Mr. Mulvey stated that water withdrawal from coastal waters, or river flows and riparian zones, even well inland, could trigger NMFS involvement. For example, construction of an intake in the water could require an Army Corps Section 404 permit, which could, in turn, require a Section 7 consultation with the NMFS. A powerplant that uses water that has been allocated to a water district as part of an existing water right, may or may not require the NMFS's involvement. Section 10 requirements could also be triggered.

As with the USFWS, Mr. Mulvey stated that the NMFS has a staff shortage and that Section 10 permits take longer than Section 7 consultations. The NMFS usually takes the full 135 days for Section 7 consultations. In reply to a question from Mr. Tooker regarding once-through cooling for coastal projects, Mr. Mulvey indicated that the NMFS would be concerned about thermal effects, chemical contaminants, impingement, and entrainment. Mr. Mulvey also identified concerns regarding projects requiring dredging. These projects would require review by the Dredge Materials Management office.

Commissioner Laurie asked about the listed species likely to be encountered in California. Mr. Mulvey stated that inland there are various salmon and steelhead species, but along the coast there are 82 groundfish species and five coastal pelagic species under management, as well as the salmon and steelhead species.

With respect to permitting processes, Mr. Mulvey encouraged early involvement at the pre-filing stage for early guidance to reduce impacts and define mitigation. Mr. Mulvey also recommended bundling projects together by habitat type and region to made the development of mitigation easier (e.g., conservation banking).

Mr. John P. Grattan, Attorney, Grattan & Galati

Mr. John Grattan stated that problems we have encounter are lack of resources, and the melding of different permit systems or permit objectives. He mentioned that USEPA's and USFWS's participation on the Governor's Green Team has had a positive effect on these agencies. He said that he thought that siting under the current emergency was being handled well, but recommended review of the process and institutional reform, because he doesn't think that either the development community or the regulators want to be in a position of dealing with emergency after emergency.

Mr. Grattan emphasized that before a developer comes in with an application, they should do a true siting alternatives analysis. If such analyses are conducted the applicants should determine what is the best location and size for their project. Mr. Gratten also said that he found it ironic that a smaller project, such as the Hanford project, that did not have a federal nexus (i.e., Section 7 consultation requirements) could experience more delays under Section 10 than a larger project with a federal nexus. However, he indicated that Ms Susan Jones facilitated the Hanford case by allowing the project to contribute mitigation funds to an existing Habitat Conservation Plan.

Commissioner Laurie asked whether with all the overlapping constraints, are there any spots in California without serious constraints. Mr. Grattan replied that there is no perfect spot, but that it is a matter of prioritizing the troubles a developer will need to address. He agreed that there is no comprehensive statewide planning relating to powerplant siting, but that developers do go through the above-cited overlay process to select sites.

Mr. Grattan said the Energy Commission, Federal agencies, and applicants have interacted well together on National Environmental Policy Act (NEPA) and CEQA coordination. He specifically cited the Western Area Power Administration's (WAPA) comfort with the Energy Commission's siting process as an example. They have been able to accept the comprehensive mitigation required by the Energy Commission to prepare an environmental assessment and make a Finding of No Significant Impact (FONSI) to comply with NEPA.

Mr. Gratten said that there have been problems with the Energy Commission's ability to reach decisions when the federal permits were delayed. The Energy Commission has had less of a problem on PSD permits where the local district has provided their determination of compliance, but the Energy Commission has been reluctant to proceed without the Biological Opinion (BO). In addition, Mr. Grattan pointed out that the federal permitting processes provide less opportunity to question or dispute agency findings or decisions (as with the Energy Commission's evidentiary process, which allows cross-examination).

Mr. Grattan suggested the following:

- Early project scoping meetings with federal agencies.

- A program, such as the San Joaquin Valley APCD's, which allows certified consultants to prepare the biological assessment reports required for the Biological Opinion.

- Energy Commission approvals that condition start of construction on the receipt of applicable federal permits. Commissioner Laurie raised the concern that prescribed conditions may have other impacts not previously addressed and thereby make the Energy Commission's CEQA analysis incomplete. Mr. Grattan indicated that such issues would occur infrequently, and could be addressed through the amendment process.

  Mr. Richard Buell, Energy Commission staff, stated that staff works with the Federal agencies to define what that mitigation is likely to be. He also noted that the Energy Commission could not knowingly adopt a mitigation measure that did not conform with federal requirements. He stated that, based on federal agency inputs, the Energy Commission has gone forward with a decision without actually having the Federal permit in hand prior to the decision.

- Provide preliminary approval of PSD permits contingent upon receipt of the Biological Opinion.

Commissioner Laurie asked about the "certified application preparer concept". Mr. Grattan indicated that the applicant would hire a certified application preparer from a list established by the agency. This would provide for consistency between applications and ensure quality applications that could be reviewed expeditiously, and the Federal agency would retain their neutrality in the review and approval process. Mr. Tooker said that information from the San Joaquin Valley APCD could be obtained. Ms. Lyons raised concerns that USEPA could have problems with such an approach and that its ethics officers would need to look at it. Getting good applications is most important, according to both Ms. Lyons and Ms. Jones, but the agencies still need to conduct the decision-making analyses.

Mr. Gary Winters, California Department of Transportation (Caltrans)

Mr. Gary Winters stated that he would focus on Caltrans' cooperative streamlining efforts under the Transportation Efficiency Act of the 21st Century (T21). The development program has a budget of approximate $2-3 billion per year, and Caltrans has 820 to 830 environmental planners to support the program. Key aspects of these efforts include:

- Recognizing cultural differences among agencies and clearly explaining project purpose and need.
- Honest and open disclosure of potential impacts.
- Cross-functional training and interagency rotational assignments (e.g., with the Coastal Commission and Army Corps of Engineers).
- Involving resource agencies at project initiation.
- Use of memoranda of understanding (MOUs) between agencies to define intentions and roles; focus on significant projects.

- Good project scopes and schedules.
- Reducing revisions of design, right-of-way, and environmental decisions.
- Making inter-agency meetings more productive, including having the appropriate people there to make decisions.

With respect to agency staffing, Caltrans has funded five positions with the USFWS, two positions with both the USEPA and Army Corps of Engineers, three with the Coastal Commission, six with CDFG, and three with the State Historic Preservation Office. A hiring freeze at NMFS has prevented the filling of their funded positions. Caltrans has used this approach to ensure review of their projects, not to guarantee project approval.

Caltrans also has interagency partnering arrangements (e.g., a tri-agency partnership with the California Environmental Protection Agency (CalEPA), the Resources Agency, and Housing) to share resources and carry out project enhancements. Caltrans is trying to work together similarly with the USFWS, NMFS, and the Federal Highway Administration (FHWA) to iron out such issues as cumulative and indirect impacts. There is already an MOU between FHWA, USEPA, and the Army Corps of Engineers to work together for resolution of Section 404 permit issues. Caltrans is also working with CDFG in hydraulics/fish passage cross-training among engineers and biologists, as well as participating on the Biodiversity Council and the Resources Agency fish passage work group.

Additional elements include programmatic approaches and agreed-upon procedures, currently being employed with respect to a variety of listed species and for cultural resources. Also, Caltrans is internally assessing cumulative and indirect impacts earlier in the project development process. Caltrans is contributing to GIS and database development work, including adding resources to the CDFG for the Natural Diversity Data Base. Additional efforts include:

- Early design decision-making and stronger change control.
- Development of a statewide standard environmental reference.
- Development of focused environmental documents.
- Mitigation banking and process improvements to incorporate mitigation.

PANEL 2: INTERCONNECTION AND LAND USE APPROVALS

Ms. Nancy Werdel, Western Area Power Administration

Ms. Nancy Werdel began with an overview of the federal lead agency role under NEPA. The lead agency designation is determined by such factors as the magnitude of agency involvement, approval authorities, and their expertise. A lead agency can request expertise from another federal agency. A lead federal agency's responsibility is to make sure that all the federal laws and regulations are complied with, including regulations implemented by USFWS, NMFS, Army Corps of Engineers, USEPA, and government-to-government relations with Native Americans. However, the Western Area Power Admininistration (WAPA or Western) relies on the applicant to actually get the required permits.

Western's process is laid out in its General Requirements for Interconnection, under its open access tariff. This is basically an instruction book for applicants that want to interconnect to Western's system. Key elements include: system studies by Western for impacts on Western's transmission system and the surrounding system; compliance by the applicant with federal laws and regulations; and a letter of agreement for reimbursement of all the funds that Western expends. Ms. Werdel suggested that Western could help other agencies to establish agreements to fund positions at the USFWS, for example, to help with interconnection evaluations.

Ms. Werdel described Western's work with the Energy Commission on the Sutter project. Western and the Energy Commission developed a MOU to develop a joint environmental document. Western prepared a EIS using the Energy Commission's analysis and documentation. Western ensured that ESA Section 7 and cultural resource consultations under federal regulations were carried out. This process included joint public meetings for scoping and the draft and final environmental documents. For the Blythe project Western was able to rely on the Energy Commission's environmental documentation and mitigation measures to reach the conclusion that significant impacts would not occur. This allowed Western to prepare an Environmental Assessment and FONSI, thus, avoiding some of the difficulties that came up in finalizing the EIS on the Sutter project. Western expects to use this process on the next three projects that it has coming to the Energy Commission.

Ms. Werdel then discussed a U.S. Department of Energy "Lessons Learned" article that was submitted to the Energy Commission. The article was based on experiences with an Arizona power plant and the Sutter project. Key points included problems with the Energy Commission staff accepting comments from the federal agency and incorporating that into their testimony, differences of opinion on significance of impacts, and differences from EIS formats expected by the USEPA. However, the two agencies have come a long way since then in working together.

Commissioner Laurie asked about Western's ability to rely on other environmental documents. Ms. Werdel indicated that this can be done provided that all of the requirements of NEPA have been addressed, which can require some supplementary work. The key, according to Ms. Werdel, is that the agencies work together to produce a joint document that meets both agencies' requirements. There could be a scenario (e.g., a transmission line across BLM-administered land) where a third agency (BLM in this example) may adopt a joint document prepared by the Energy Commission and Western if it covered their NEPA requirements.

In response to a question from Mr. Tooker, Ms. Werdel stated that the final staff assessment (FSA) for the Sutter project was Western's Draft EIS. Western then produced a Final EIS for review and public comment prior to the Western decision.

Duane Marti, U.S. Department of Interior, Bureau of Land Management (BLM), and Bob Hawkins, U.S. Department of Agriculture, Forest Service

Mr. Marti introduced a three-page paper that they submitted to the Energy Commission. He explained that both the Bureau of Land Management (BLM) and Forest Service are Federal land management agencies with similar processes.

Mr. Marti described a February 16, 2001 memorandum from President Bush to the Secretaries of Defense, Interior, Agriculture, and Commerce and to the USEPA Administrator that directs all relevant federal agencies to expedite federal permit reviews and decision procedures with respect to the siting and operation of power plants in California.

Mr. Marti then described the agencies' NEPA processes. He explained that the agencies have both done joint environmental reviews with California lead agencies. One of the advantages of the joint review is that the mandated actions, like the public scoping meetings, public review, and public comment period can be done together. A key is the designation and leadership of the federal and state lead agencies. Sometimes the state agency can take more of the lead, but a federal lead agency would still need to be designated. Mr. Marti also stated that the BLM sometimes prepares the NEPA document by incorporating by reference the CEQA document. Mr. Hawkins also explained that the federal agency role would be proportionate to the magnitude of the federal jurisdiction involved.

Addressing an earlier question regarding use of environmental documents, Mr. Marti stated that BLM will evaluate the adequacy of the document to meet NEPA requirements. Generally, BLM finds that older documents are usable if the current proposed action was clearly analyzed, the resource conditions and circumstances are basically unchanged from when they were being analyzed, and no new significant or appropriate alternatives have been identified by the public. With older documents, things may have changed a lot, but some of the information may still be useful. Commissioner Laurie indicated that similar considerations apply for use of older documents under CEQA.

Mr. Marti stated that the key information needed for a timely joint review includes: good project information, maps, project schedules, and previous relevant CEQA and NEPA documents, along with early consultation among the agencies and applicant to develop the best initial project proposal (e.g., in route selection across federal lands).

Ms. Townsend-Smith asked how long a project review usually takes. Mr. Hawkins stated that a complex transmission line across multiple forests and BLM land would easily take two years to process. The time required depends on the complexity of the issues and alternatives analyzed. Both men stated that it would be difficult to say how their agencies could respond to a 21-day or four-month process.

They also discussed their appeals processes. BLM decision appeals can be filed within 30 days of the decision to the Interior Board of Land Appeals (IBLA) under 43 CFR 4. IBLA can impose an immediate stay of construction. IBLA decisions have no required deadline. Forest Service decision appeals can be filed within 45 days of a decision.

Filling an appeal results in a mandatory stay of construction, but is reviewed within 45 days. Construction can not resume until15 days after the decision on the appeal is made. A 30-day review period is required for initial decisions for public notice and review of the decision documents. The total time for an appeal is a minimum of 135 days. Mr. Hawkins stated that it realistically takes longer.

Commissioner Laurie asked about statewide mapping of resources and constraints (i.e., geographical information system (GIS)). Mr. Hawkins stated that some information (e.g., land management plans) is available at the state level, but more specific information is at the individual National Forest offices. In early consultation at the local level using GIS information is very helpful in identifying constraints to powerplant siting. For example, wilderness areas can be defined as constrained. Mr. Marti also emphasized that wilderness areas, wilderness study areas, and wild and scenic rivers represent constraints. The BLM uses GIS for these purposes. Mr. Marti also stated that the BLM and Forest Service have designated energy production areas and utility corridors. He mentioned a comprehensive study of utility corridors done in the early 1990s. Permitting of projects within designated corridors would be easier, and maps showing these corridors are available to applicants.

Mr. Tooker asked whether information on constrained areas was available on the internet. Both Mr. Hawkins and Mr. Marti indicated that it is not comprehensively available. Ms. Werdel stated that Western is working with the Army Corps of Engineers to get WAPA's transmission lines on the Army Corps of Engineer's mapping system.

Mr. Marti then described the heavy workloads at BLM and Forest Service, and the availability of cost recovery processes for additional staff or consultants to process permits. Mr. Hawkins also stated that applicants can conduct some of the necessary studies under the supervision of Forest Service specialists. Mr. Marti cited the advantages of MOUs with other agencies to share the workload and reduce duplication of efforts. Commissioner Laurie expressed appreciation for the efforts of other state and federal agencies in giving attention to Energy Commission priorities. Mr. Tooker stated that the Energy Commission staff, has developed MOUs with federal agencies and recognizes their benefits.

Mr. Stephen V. Quesenberry, California Indian Legal Services

Mr. Stephen Quesenberry stated that there are 109 federally recognized tribes in California, which are those that have a government-to-government relationship with the United States. The size of the Indian lands in California is approximately half a million acres. The individual reservations and rancherias range from less than 50 acres to more than 100,000 acres.

In response to a question from Commissioner Laurie, Mr. Quesenberry stated that California Indian Legal Services receives some of its funding from the federal government, some from the state, and also some directly from tribes.

Mr. Quesenberry stated that with many tribes the tribal councils have been delegated authority by the tribal members to make final decisions relating to environmental impacts on the reservation. But there are a significant number of other California tribes that operate on a general council governing concept, which means that any major decisions made by the tribe go back to the entire tribe for ratification. This can sometimes delay decision-making.

The jurisdictional framework for projects on tribal lands can be complicated by such factors as land title, who is the project developer, and funding source. In general, in the absence of express Congressional authorization, state laws and regulations do not apply on Native American lands. A number of Supreme Court decisions have qualified tribal sovereignty in certain circumstances such as where the lands are fee lands, the activities may involve non-Native Americans, or there may be significant off-reservation impacts of on-reservation activities. Key aspects of siting a facility on Native American lands include:

- The tribe is a sovereign entity there, with a unique status under federal law.
- The federal government, in implementing federal law, has to do so consistent with its trust responsibility to the tribes.

Mr. Quesenberry then described how there has been a dramatic change in the state's approach to dealing with tribal governments. There has been an increased recognition that the tribes do have sovereignty within their lands and over their people. There has been greater effort in environmental regulation, which affects both reservation and off-reservation areas, to resolve jurisdictional issues without litigation. He stated that a draft inter-governmental MOU that includes federal agencies, the tribes, and the state, which was prepared by Energy Commission staff, is a really good step towards doing that.

Mr. Quesenberry stated that the relationship between the federal government and the tribes is something that is very important to understand. The federal government may have obligations to the tribes that are unique in our legal system. The obligations of that relationship are manifested mainly through a federal tribal consultation process, that is written into law, regulation, and executive orders relating to such issues as policies or actions that may affect tribal interests, impacts on sacred sites and cultural resources, and management of endangered species.

In reply to a question from Ms. Townsend-Smith, Mr. Quesenberry stated that a tribe may be able to develop a power plant without going through the NEPA process, where it was developing it with its own resources on tribal land, and the action would not require some form of federal approval. However, in most cases there would be some federal involvement that triggers NEPA. Regarding state regulation, off-reservation impacts raise a question of whether the state has an interest that it is entitled to protect. Mr. Quesenberry stated that the best approach would be to address the jurisdictional questions without litigation.

In answer to a question from Commissioner Laurie, Mr. Quesenberry indicated that tribal consent to a jurisdictional agreement with the Energy Commission on a particular permitting process would have to be addressed on a tribe-by-tribe basis. However, he also stated that, although California is a huge state with a large number of tribes, there is a statewide council of tribes that deals with forestry issues, and that model could be developed in the area of power generation, as well.

Mr. Quesenberry stated that NEPA compliance can be required if a tribe had a private developer that was going to be using tribal lands for a project, because there's a specific requirement under federal law that contractual agreements related to tribal lands must be approved by the Secretary of the Interior. In addition, tribes are generally subject to federal laws, such as the Clean Air Act and the Clean Water Act. Under these laws the USEPA may delegate, under certain criteria, authorities to the tribes as they would to the states. Not many tribes in California have met those criteria.

Mr. Quesenberry also mentioned the Native American Graves Protection and Repatriation Act and the National Historic Preservation Act, which have protection and consultation provisions with respect to cultural resources. Federal approval would be required for leases and rights-of-way (both new rights-of-way or expansion of existing rights-of-way). On tribal land, tribal consent would be required, as well. There are comprehensive regulations in both of those areas under Title 25 of the Code of Federal Regulations. He reiterated the potential value of intergovernmental MOUs to expedite environmental reviews.

Mr. Quesenberry recommended a publication of the USEPA, prepared by the National Environmental Justice Advisory Council, Indigenous Peoples Subcommittee. It is a guide on consultation and collaboration with Indian tribal governments in environmental decision-making.

Mr. Tooker asked about the permitting of a large stationary source on a Native American reservation without a significant air regulatory program, and Mr. Quesenberry indicated that USEPA would probably be the permitting entity. For siting, the jurisdiction may not be well defined, NEPA may apply, and the use of a MOU may be the best method to sort out the jurisdictional issues.

Ms. Monica Schwebs, Energy Commission

Ms. Monica Schwebs, staff counsel, described some of the pre-workshop meetings that were held with various agencies (including USFWS, USEPA, NMFS, BLM, the Forest Service, WAPA, and the California Public Utilities Commission) regarding permitting and siting, and the ESA in particular. They brainstormed on how to improve the siting process and generated some preliminary recommendations (see the recommendation section below).

Commissioner Laurie asked that these recommendations be formally presented at the next Siting Committee Meeting. A question from the audience regarding the 21-day process was presented and discussed briefly among Commissioner Laurie, Mr. Tooker, and Ms. Townsend-Smith, before the meeting was adjourned.

ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 1: What conflicts exist between the Energy Commission siting process and federal permit processes?

1. *What Federal permits or environmental reviews need to be coordinated with the Energy Commission siting process?*

   Federal permits that need to be coordinated include:

   - Permit processes under the Endangered Species Act, Section 7 Consultations or Section 10 Take Permits.
   - Prevention of Significant Deterioration (PSD) permits under the Federal Clean Air Act, which are, in some cases, delegated to local air pollution control districts.
   - National Pollutant Discharge Elimination System (NPDES) permits, generally administered by local agencies.
   - Federal land use entitlements (e.g., rights-of-way and special use permits) for pipelines and transmission lines or other facilities that are located on or cross federal lands, and
   - Permitting requirements related to Indian Reservations, tribal treaty rights, and Native American concerns.

2. *What problems have been encountered in coordinating federal and state reviews of electricity generating, transmission line and gas pipeline projects?*

   The problems that have been encountered include:

   - Lack of sufficient information for processing federal permits.
   - Lack of sufficient federal agency staff to review applications in a timely manner.
   - Difficulty in developing appropriate mitigation strategies or in establishing mitigation banks.
   - Difficulty of coordinating efforts between federal, state and local agencies to eliminate redundancies.

3. *What guidance does the Energy Commission need to provide applicants to better coordinate permitting and environmental review with federal agencies?*

   a. *What is the optimal timing for submitting permit applications and data to federal agencies to facilitate licensing by the Energy Commission?*

   b. *What steps should be taken to assure that acceptable application materials are submitted?*

      Most all of the panel member emphases the need for early consultation with federal agencies, to ensure that acceptable data is submitted. Panel member suggested that federal agency representative should be invited to pre-filing and project Energy Commission staff meetings. The panel member also recommended that 1) guidelines for information requirements should be provided to potential applicants, 2) the agencies should maintain good and current database of threatened and endangered species, and 3) the agencies should establish habit conservation banks, which applicants could contribute to meet requirements for mitigation.

4. *Can the Commission do more with the permitting agencies to coordinate schedules, and, perhaps, come to agreement on minimum standard timelines for review cycles and decision milestones that can be reliably adhered to?*

   Staff and panel member suggest identifying federal agency liaisons who would assigned the task of assuring timely review by his or her agency. This person could also serve as an expert resource person for others in his or her agency and for applicants. Where both NEPA and CEQA reviews are required, signing a memorandum of understanding (MOU) that sets out the responsibilities of each agency, including timelines for review.

5. *What steps should be taken to better plan for Endangered Species Act (ESA) review for powerplant projects?*

   If ESA or NEPA review is required, promptly identify the federal lead agency and nexus to ensure that the review can begin as soon as possible. Upon distribution of applications to federal agency liaisons, request the liaisons to determine the federal lead agency and federal nexus for USFWS or NMFS review.

6. *Regarding appeals to the U.S. Environmental Protection Agency's (EPA) Environmental Appeals Board (EAB):*

   a. *What can be done to promote timely EAB decisions?*

   b. *Can EAB's governing regulations be changed such that a stay can only be based on the merits of the appeal? Can the regulations be revised to more precisely define the scope of what may be considered in the appeal?*

      The Energy Commission and federal agencies should first ensure that they are producing sound analyses, which address all the requirements of federal regulations. Once an appeal is filed, the Energy Commission staff should work with federal agencies to ensure that the EAB has relevant information on which to make timely decisions regarding appeals.

ISSUE 2: How can the Energy Commission siting process and the federal permit and environmental review process be better coordinated?

1. *For projects to be reviewed under both the California Environmental Quality Act and Federal National Environmental Policy Act (NEPA), how should the reviews be coordinated?*

   a. *What models have worked best on past siting cases?*

   b. *Is there a need to formalize coordinated NEPA/CEQA review processes and standardize documentation?*

Joint NEPA and CEQA review is the best way to eliminate duplication and to facilitate timely review. The agencies should meet early to develop a MOU to identify the responsibilities of each agency, to identify the scope and content of the environmental documents, and to establish schedules preparation for environmental documents. The Blythe case was a good model for a process that worked well.

2. *For projects on or near tribal land, how should project review be coordinated with tribal governments?*

   The Energy Commission should make early contacts with tribal governmental to ensure their input to the siting process.

3. *What formal or informal agreements are needed at an agency level or staff level?*

   a. *Are agency Memorandums of Understanding (MOUs) required?*

      Yes.

   b. *What regulation changes are necessary to incorporate formalized procedures?*

      It does not appear that regulation changes are necessary to formalizes working relationships. Regulation changes could be used to clarify informational requirements for applications and to identify mitigation requiremnts.

4. *Where agency staff resource/workload (and, hence, project priorities) are significant issues, how can the Commission, applicants, and agencies work together to maintain schedules and promote permit processing predictability and reliability? Concepts could include:*

- *Designate agency staff to work on energy projects as their highest priorities.*
- *Funding of additional dedicated agency personnel – either on a project-specific basis by applicants or through a fund administered by the Energy Commission or the agency based on projections of applications and charging of fees to applicants on a pro-rata basis.*
- *Re-allocations of funds or new appropriations to fund additional dedicated positions.*
- *Utilize applicant-funded but agency-administered and supervised consultant contracts to conduct the analytical portions of the permit processing efforts.*

Staff and panel members supported all of the above and identified other measures to increase staff resources or make better utilization of resources. See Staff Recommendations below for more details.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

FUNDING RECOMMENDATIONS

Problem: There is an acute need for additional staff and consultant money for federal agencies that must provide approvals for California energy projects.

Explanation:

- For example, a key USFWS office is operating with a third of its authorized staff, is under a hiring freeze, and has no consultants. NMFS and Forest Service are in similar positions.
- There are no signs from Washington that the hiring freeze will be lifted any time soon or that there will be increases in appropriations.
- The number of available personnel must increase to cover the surging demand for federal environmental review of energy projects – not only generation, but also electric transmission line and natural gas line construction.

Recommendation:

(1) The Energy Commission should make a formal request to the Bush Administration to lift the hiring freezes and request additional appropriations for reviewing energy facility permits applications.
(2) If the federal government does not act quickly, the Energy Commission should look into the feasibility of using state money to fund federal positions (as CalTrans has done) or provide consultant assistance to the federal agencies.

PROCESS RECOMMENDATIONS

Problem: The need to expedite review requires that federal and state governments better coordinate their permit approval processes to avoid any unnecessary delays.

Recommendations:

While, in general, federal and state approval processes have become fairly well coordinated, there is room for improvement. We recommend these process modifications:

(1) Federal liaisons: Have each federal agency identify an Energy Commission liaison assigned the task of assuring timely review by his or her agency. This person could also serve as an expert resource person for others in his or her agency and for applicants.
(2) Involvement in Pre-filing: Involve the federal agency liaisons in Energy Commission pre-filing meetings for the purpose of identifying and correcting problems with projects early to avoid delays later in the process.
(3) Prompt identification of lead agency and nexus: Upon distribution of applications to federal agency liaisons, request

a) Prompt identification of the federal lead agency, if NEPA review is required.

b) Prompt identification of any federal nexus requiring review by USFWS or NMFS, if endangered species may be affected.

Note: The federal agencies indicated that prompt identification of the lead agency and any federal nexus would assist them by making it clear quickly what the obligations of the agencies will be.

(4) Coordinated NEPA/CEQA Review: Where both NEPA and CEQA reviews are required, assure that duplication of effort is avoided. Signing a MOU that sets out the responsibilities of each agency is a good way to avoid duplication.

(5) Invite federal agencies in to Energy Commission internal staff project meetings, when appropriate to facilitate inter-agency communication.

(6) Use of Energy Commission staff analysis for DFG take permit: Clarify state law to facilitate DFG use of a Energy Commission staff analysis as an adequate CEQA document for issuance of a take permit.

Targeted Planning Recommendations:

Problem: The lack of advanced planning that identifies known constraints, delays the Energy Commission's licensing process.

Recommendations:

Some examples of areas where targeted advance planning could be useful are:

(1) Providing guidance regarding baseline data need for CWA Section 316(b) report on cooling water intakes: Several of the coastal plants have been delayed because applicants have provided inadequate baseline data for purposes of establishing mitigation for the impact of cooling water intakes. The Energy Commission and interested federal agencies should provide q guidance regarding what is required to avoid future delays.

(2) Determining how to handle growth-inducing impacts. An issue that USFWS has raised in both electricity generation and transmission cases is whether there should be mitigation for growth-inducing impacts. USFWS has faced litigation on this issue. Setting up agency-to-agency discussions to discuss how to handle growth-inducing impacts facilitate USFWS review and prevent federal litigation from interfering with federal approvals.

Long-Range Planning Recommendations:

Problem: The lack of adequate databases and mitigation banks will continue to delay federal permitting processes.

Recommendations:

Some examples of important long-range planning are:

(1) Maintaining a good and current database of threatened and endangered species: A good publicly available database can help applicants avoid causing impacts on

endangered species, and therefore, expedites permitting. Maintaining such a database has become more important with the advent of competition in generation since many applicants are reluctant to tell agencies of their plans in advance for competitive reasons.

(2) Establishing habitat conservation banks: Perhaps the most time-consuming aspect of ESA review is determining what mitigation conditions must be imposed. This can be facilitated by ready availability of habitat conservation banks. The adequacy of current state banks should be reviewed to determine whether more are necessary for planned energy projects.

(3) Becoming a non-federal designated lead agency for ESA compliance: The Energy Commission should investigate whether it can become a non-federal designated lead agency for ESA compliance.